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Calculation for the Cost of Using Alternate Fuels Under the Powerplant and Industrial Fuel Use Act of 1978; Proposed Rulemaking and Public Hearing

DEPARTMENT OF ENERGY

Economic Regulatory Administration

10 CFR Parts 503, 504, 506

[Docket No. ERA-R-80-17]

Calculation for the Cost of Using Alternate Fuels Under the Powerplant and Industrial Fuel Use Act of 1978

AGENCY: Economic Regulatory Administration, Department of Energy.

ACTION: Notice of Proposed Rulemaking and Public Hearing.

SUMMARY: The Economic Regulatory Administration (ERA) of the Department of Energy is issuing this notice of proposed rulemaking to implement certain cost calculation provisions of the Powerplant and Industrial Fuel Use Act of 1978 (FUA). FUA provides for exemptions from the prohibitions of the Act in the case of new and existing facilities where it is demonstrated that the cost of using an alternate fuel "substantially exceeds" the cost of using imported petroleum. The Act also authorizes ERA to issue orders prohibiting the use of petroleum and natural gas in certain existing facilities if ERA finds that the use of coal or another alternate fuel as a primary energy source is "financially feasible." In addition, ERA is empowered to issue prohibition orders if use of a mixture of petroleum or natural gas and coal or an alternate fuel is found to be "technically and financially feasible." This proposed rule provides the methodology for these FUA cost calculations and solicits comments thereon.

DATES: Comments by August 20, 1980, 4:30 p.m. Requests to speak by: July 7, 1980. Hearing date: July 10, 1980, 9:30 a.m.

ADDRESSES: Send comments and requests to speak to: Department of Energy, Public Hearing Management, Docket No. ERA-R-80-17, Room 2313, 2000 M Street, N.W., Washington, D.C. 20461.

HEARING LOCATION: Department of Energy, Room 2105, 2000 M Street, N.W., Washington, D.C. 20461.

FOR FURTHER INFORMATION CONTACT:

William L. Webb (Office of Public Information), Economic Regulatory Administration, Department of Energy, Room B-110, 2000 M Street, N.W., Washington, D.C. 20461 (202) 653-4055.

Stephen M. Stern (Regulations and Emergency Planning), Economic Regulatory Administration, Department of Energy, Room 7002, 2000 M Street, N.W., Washington, D.C. 20461 (202) 653-3217.

Robert L. Davies (Office of Fuels Conversion), Economic Regulatory Administration, Department of Energy, Room 3128-L, 2000 M Street, N.W., Washington, D.C. 20461 (202) 653-3649.

G. Randolph Comstock (Office of General Counsel), Department of Energy, Room 6G-087, 1000 Independence Avenue, S.W., Washington, D.C. 20585 (202) 252-2967.

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I. Background

Proposed rules implementing Sections 211(a)(1), 212(a)(1)(A), 311(a)(1) and 312(a)(1)(A) regarding exemptions in the case of facilities for which it is demonstrated that the cost of using an alternate fuel "substantially exceeds" the cost of using imported petroleum were originally published on November 17, 1978, at 43 FR 53974, 54005, 54030, and on January 29, 1979, at 44 FR 5808, 5820, 5840. Interim rules were subsequently adopted on May 17, 1979, at 44 FR 28950, 28979, 28999, on July 23, 1979, at 44 FR 43176, 43191, 43209, and additional comments were requested.

After considering these comments, ERA determined that it was inappropriate to adopt a final rule with respect to the cost calculation at that time. The cost calculation provisions of the interim rules were revoked, and ERA declared its intent to issue another notice of proposed rulemaking.

II. Comments Requested

This notice of proposed rulemaking provides a significant change from the previous interim rules by which ERA will determine whether a facility qualifies for an exemption based on cost. Petitions submitted before revocation of the pertinent interim rule cost calculations that use these calculations and that are still pending before ERA may, at the petitioner's option, (1) be analyzed using this proposed rule as guidance, or (2) be held in abeyance pending finalization of a cost calculation procedure. However, no final administrative action will be taken with respect to any petition which requires the use of a cost calculation until ERA has adopted a final rule. Petitions using cost calculations that are submitted to ERA after revocation of the pertinent interim rule may use this proposed rule as guidance.

The following sections address specific aspects of the cost calculation which is now being proposed by ERA.

(a) *Cost calculation methodology.* Under the interim rules, the cost calculation methodology was based on a ratio of the cost of using an alternate fuel to the cost of using imported oil. [Cost is defined under FUA Section 103(a)(2) as the total costs (both operating and capital incurred over the estimated remaining useful life of the unit) discounted to present value.] If this ratio exceeded a fixed threshold (1.3), an exemption was granted. This threshold ratio represented a combination of ERA's expectation of future changes in fuel prices in real (without inflation) terms and other factors.

In the preamble to interim regulations (44 FR 43185, July 23, 1979), ERA also requested comments on a number of other approaches for determining when the cost of using an alternate fuel would substantially exceed the cost of using imported oil. The overwhelming majority of commenters favored the use of a net present value technique which closely follows private sector investment decision evaluation procedures. ERA now proposes to adopt this recommended approach [where the present value of using oil is subtracted from the present value of using alternate fuel such that if the difference (the net present value) is positive an exemption would be granted] for the following reasons:

1. The net present value approach more explicitly recognizes expected future increases in fuel prices either through (a) explicit fuel price trajectories for imported oil and alternate fuel or (b) an annuity added to the price of imported oil which recognizes changes over time in the price of imported oil relative to coal. ERA is proposing that the substantially exceeds provisions of the Act will then be accommodated by adding a premium to the price of petroleum used in the cost calculation.

2. In addition, ERA has determined that the ratio technique does not readily identify the costs associated with

mixtures or the dispatching of existing powerplants on an economic basis. The net present value technique, however, will adequately identify these costs since it results in an examination of the marginal capital investment and the operating, maintenance, and delivered fuel expenses associated with the comparative choices.

ERA now believes that for the reasons cited above the net present value approach has advantages that outweigh the previously stated benefits of using a ratio as described in the interim rule (44 FR 28957, May 17, 1979). ERA proposes to structure the cost calculation so as to reflect the net present value technique. This form of the cost calculation requires a specification of expected future fuel price escalation, using either explicit fuel price trajectories or an annuity, [and a substantially exceeds premium as more fully discussed in paragraphs (g) and (i) below]. Such a comparison includes the capital, and the operating, maintenance, and fuel costs associated with any particular fuel choice, expressed in real terms discounted to present value.

Under FUA, a facility shall be granted an exemption to use oil or natural gas on the basis of cost when coal or another alternate fuel will not be available at a cost which "based upon the best practicable estimates, does not substantially exceed the cost, as determined by rule by the Secretary, of using imported petroleum * * *." ERA proposes to implement this language by requiring that these net present value cost calculations reflect (1) the price of imported petroleum, (2) any projected increase in fuel prices, and (3) a premium attributable to the "substantially exceeds" provision.

(b) *Specification of discount rate.* The statutory definition of cost (Section 103(a)(20)) requires that the cost calculation procedures use a discount rate. We have tentatively set this discount rate in real terms at 7.7 percent for all installations and at 2.9 percent for all powerplants.

ERA believes that firm- or company-specific discount rates should not be used for the cost calculation because a firm- or company-specific discount rate, all else being equal, would increase the likelihood of less efficient firms receiving an exemption on the basis of cost and reduce the likelihood of more efficient firms obtaining an exemption on the basis of cost. ERA does not believe that, under a statute designed to conserve petroleum and natural gas for uses having no feasible alternative fuels or raw material substitutes, the opportunity to burn such fuels should depend upon economic factors unrelated to the availability of alternate fuels. Calculations for the financial feasibility finding for existing facilities would continue to use a cost calculation which employs a firm-specific discount rate (see §§ 504.5(g) and 506.2(g)).

For the purposes of the cost calculation, ERA proposes to use discount rates which are the means of samples of firms' real, *after tax,* weighted average marginal cost of capital. These means are the results of a contractor study performed for ERA. The contractor analyzed a sample of 118 Class A and Class B utilities and a sample of 50 energy-intensive industrial firms. The mean of the utility sample was 2.9 percent per annum, and the mean of the industrial sample was 7.7 percent per annum. ERA decided to use this particular study as a basis for setting the discount rate because it was more narrowly focused on the population most likely to be affected by FUA than were other studies available to ERA. A summary of the study was published in the **Federal Register** (44 FR 43222–23, July 23, 1979). A copy of the report was placed in the record of this rulemaking and is available from ERA. Comments are invited on (1) the choice of discount rate, (2) the use of one discount rate for all powerplants and another for all industrial firms, (3) the above mentioned study of the after tax weighted average marginal cost of capital, and (4) other accepted methods for computing cost of capital and whether publically owned utilities (e.g., municipal utilities) should have a different discount rate than privately owned utilities. ERA expects to periodically revise this study and change discount rates after due public notice and comment.

(c) *Capital outlays.* Capital outlays include all items that are capital investments for Federal income tax purposes.

If the petitioner constructs a new oil or gas fired MFBI and then petitions for an exemption, he must include all expenditures made as part of the cost of using imported oil.

In determining the cost of using an alternate fuel fired unit, the petitioner may not use prior outlays attributable to an abandoned oil or gas fired unit unless the costs may also contribute to the alternate fuel fired unit.

Comments are solicited on the scope of the items which should be included as capital outlays.

(d) *Facility output lost due to derating or replacement.* If an existing facility would be derated because of a shift from oil to an alternate fuel, the petitioner may choose to account for the loss of that output for the purpose of the cost calculation. Provisions have been made for the required capital, operations, maintenance, and fuel cash outlays so that the overall costs are minimized.

If the size of the unit needed for make-up capacity is smaller than a unit which would be excluded from aggregation in § 500.2 of these regulations and, if the least cost alternative is an oil- or gas-fired facility, the costs of such a make-up facility will be considered in the cost formula.

Questions concerning proper accounting for the make-up capacity should be raised in a prepetition conference if the capacity of the make-up unit is FUA jurisdictional when aggregated and the least cost alternative is an oil- or gas-fired facility. If the least cost alternative is an oil- or gas-fired unit that appears likely to receive an exemption from the prohibitions of Title II of the Act, the costs of that alternative will be included in the cost test as the costs of make-up capacity.

Furthermore, if an alternate fuel fired replacement facility must be constructed, the cost of using an alternate fuel and imported oil must be computed over the remaining useful life of the oil/natural gas fired unit. ERA proposes to annualize the cost of the replacement facility and to compute present value cost over the remaining lifetime of the oil/natural gas-fired unit.

Assume, for example, that a utility petitioner requests an exemption on the basis of cost from the 1990 ban on natural gas use in powerplants and that the petitioner's powerplant cannot burn coal or other alternate fuel and would have 20-years remaining life in 1990. This rule proposes that the petitioner would compute the cost of using imported oil (i.e., natural gas priced at imported oil), over a 20-year life. The capital cost of using alternate fuel(s) would be determined for a new powerplant and then annualized. The comparative net present value of using alternate fuel and imported oil would then be computed over the same 20 year period.

(e) *Fuel inventories.* In computing capital costs, ERA is proposing that the petitioner include the cost of fuel inventories customary in business practice ERA has proposed uniform inventory requirements for steam turbine powerplants, combustion turbine powerplants, combined cycle powerplants, and industrial installations.

Data on fuel inventories on hand at each utility plant in the United States are gathered by the Federal Energy Regulatory Commission on its Form 4. The data for oil-fired steam turbines and

combustion turbine powerplants for the years 1975 and 1976 are summarized as follows: For oil-fired steam turbine plants the inventories were 81 and 75 days in 1975 and 1976, respectively; the average was 78 days of inventories. For gas turbines, 157 and 128 days of inventories were on hand in 1975 and 1976, respectively, averaging 142 days.

For major industrial users, the Strategic Petroleum Reserve Office of DOE contracted for a study of inventory management in the petroleum industry. This report "Inventory Management in the Petroleum Industry," which can be obtained from ERA, is the basis for ERA estimates of inventory practice by industry. ERA has concluded that common industry practice is to maintain 21 days' storage or to keep installed storage tanks 60 percent full, whichever is greater.

In sum, ERA believes that all fuel inventories for the same type of unit should be calculated as follows:

Steam turbine powerplants, 78 days.
Combustion turbine powerplants, 142 days.
Combined cycle powerplants, 142 days.
Installations, 21 days or 60 percent of storage capacity, whichever is greater.

The above presumptions may be rebutted upon presentation of evidence deemed acceptable by ERA.

In addition, in the case of conversions of existing facilities which leave amounts of fuel which cannot be utilized, ERA is proposing to require the accounting of the salvage value of such unusable fuel. ERA solicits comments on whether fuel storage requirements are appropriate for petitioners proposing to use natural gas, and if so, at what levels.

(f) *Operating, maintenance, and fuel costs.* Alternative methods for computing annual cash outlays for operating, maintenance, and fuel are discussed below. Whichever method is selected must be used consistently for all units considered. Comments are invited on each of these methods.

(1) *Powerplants.* The annual cash outlays for operating, maintenance, and fuel expenses for a powerplant may be computed by the following methods:

(i) Assume the energy produced by the powerplant equals seventy (70) percent of design capacity times 8760 hours for each year during the life of the powerplant, or

(ii) Assume all powerplants in the region are economically dispatched. The regional cash outlays for operating, maintenance, and fuel expenses are the corresponding expenses for purposes of the cost calculation. The region must be the petitioner's electrical region unless the petitioner can show that such integrated operation is unlikely to be achieved midway through the useful life of the powerplant, and an alternative acceptable to ERA is proposed. If the petitioner based these calculations on an economic dispatch analysis, and an exemption is granted, the petitioner will have to certify, subject to penalties, that the proposed unit will not use more oil than it would have used in the dispatch analysis.

A third method, identified in (iii) below, may be used by existing powerplants unless the energy generated by the alternate fuel fired powerplant is demonstrated to be less than that calculated with method (ii).

(iii) For a powerplant that has been in operation for at least two years, assume that it will generate an amount of energy equal to the average amount of energy generated for the last five years (or the life of the powerplant if it is less than five years). However, if the loss due to derating (discussed above) is recovered, the petitioner must calculate these costs based on dispatching his region.

(2) *Installations.* (i) When computing the annual cash outlays for operating, maintenance, and fuel expenses for a new installation, the petitioner must specify the firing rates and the length of time each firing rate will be maintained.

(ii) When computing the annual cash outlays for operating, maintenance, and fuel expenses for an existing installation, the petitioner may specify one of the following methods:

(A) Assume in the computation the actual power or steam generation schedule of the installation in which conversion is being considered and, if applicable, the generation schedule of any additional unit required due to derating of the facility being converted. If the loss of output due to derating is recovered for the purpose of the cost calculation, method (A) must be used.

A second method (B) may be used unless the energy or steam produced by the alternate fuel fired unit is demonstrated to be less than that computed by method (A).

(B) If the installation has been in operation for at least two years, assume it will annually generate an amount of energy or steam equal to the average amount of energy or steam produced annually for the last five years (or the life of the installation if it is less than five years but at least two years).

ERA proposes that if an exemption is granted, the petitioner will have to certify, subject to penalties, that the unit will burn no more oil than the maximum amount he could have specified and still have been granted an exemption.

(g) *Incorporation of future fuel prices.* In this notice, ERA is proposing two versions of a methodology which incorporates expected future fuel prices for the purposes of the cost calculation. One method involves adding a fixed annuity to the price of oil to reflect future increases in the price of oil relative to that of coal and other alternate fuels (see Appendix II–B). Another method allows petitioners to use the lesser of either the explicit price trajectories for oil and alternate fuels or a dollar per barrel maximum fixed annuity (see Appendix II–A).

To develop the price trajectories and the annuity proposed in either Appendix, ERA examined a variety of fuel price projections derived from documented analyses and then calculated the equivalent annuities. To determine the change in real imported oil price relative to that of coal, ERA assumed the standard cost calculation parameters associated with a new installation going on-line in 1980 having a 40 year useful life and using a 7.7 percent discount rate.[1]

ERA evaluated five forecasts made by three different sources:

- Energy Information Administration (EIA) of DOE: high medium, and low scenarios;
- Data Resources, Inc. (DRI);
- Wharton Econometric Forecasting Associates, Inc. (Wharton).

(1) EIA annually forecasts the prices of imported oil and industrial coal for three scenarios—high, medium, and low. The prices shown below[2] in 1979 dollars were used by ERA to calculate annual rates of price increase[3] and a range of annuity equivalent values based on two assumptions of current fuel oil prices.[4]

(i) EIA high scenario:

Year	Imported crude oil (barrels)	Industrial coal (MMBtu)
1985	$38.57	$2.10
1990	44.07	2.28
1995	55.63	2.35
2000	60.00	2.44
2010	60.00	2.59
2020	60.00	2.98

These price forecasts yield the following rates of increase:

Period	Imported crude oil (percent)	Industrial coal (percent)
1980–85	5.1	3.9
1985–90	2.7	1.7
1990–95	4.8	0.6
1995–2000	1.5	0.8
2000–10	0	0.6
2010–20	0	1.4

and result in equivalent annuities of $11.71 and $13.75 per barrel, depending on the price of fuel oil used.[4]

(ii) EIA medium scenario:

Year	Imported crude oil (barrels)	Industrial coal (MMBtu)
1985	$32.07	$2.10
1990	36.54	2.26
1995	40.58	2.36
2000	43.00	2.43
2010	43.00	2.58
2020	43.00	2.94

These price forecasts yield the following rates of increase:

Period	Imported crude oil (percent)	Industrial coal (percent)
1980–85	1.6	3.9
1985–90	2.6	1.5
1990–95	2.1	0.9
1995–2000	1.2	0.6
2000–10	0	0.6
2010–20	0	1.3

and result in equivalent annuities of $3.27 and $4.15 per barrel.[5]

(iii) EIA low scenario:

Year	Imported crude oil (barrels)	Industrial coal (MMBtu)
1985	$27.00	$2.09
1990	27.00	2.24
1995	27.00	2.33
2000	27.00	2.40
2010	27.00	2.53
2020	27.00	2.79

These price forecasts yield the following rates of increase:

Period	Imported crude oil (percent)	Industrial coal (percent)
1980–85	−1.5	3.8
1985–90	0	1.4
1990–95	0	0.8
1995–2000	0	0.6
2000–10	0	0.5
2010–20	0	1.0

and result in equivalent annuities of −$4.79 and −$5.03 per barrel.

(2) DRI forecasts the following prices for imported crude oil and industrial coal (converted from nominal to 1979 dollars):[6]

Year	Imported crude oil (barrels)	New contract coal (MMBtu)
1980	$30.73	$1.45
1985	35.70	1.85
1990	41.32	2.10
1995	48.04	2.30
2000	55.60	2.48

which yield the following price increase rates:

Period	Imported crude oil (percent)	New contract coal (percent)
1980–85	3.0	5.0
1985–90	3.0	2.5
1990–95	3.1	1.9
1995–2000	3.0	1.5

and equivalent annuities between $5.83 and $10.44 per barrel.[7]

(3) Wharton forecasts the following prices for imported crude oil and domestically produced (f.o.b. mine mouth) coal (converted from nominal to 1979 dollars):[8]

Year	Imported crude oil (barrels)	Domestically produced coal (MMBtu)
1980	$29.29	$27.61
1985	35.74	28.56
1990	39.15	29.21

which yield the following price increase rates:

Period	Imported crude oil (percent)	Domestically produced coal (percent)
1980–85	4.1	0.7
1985–90	1.8	0.5

and equivalent annuities between $6.44 and $11.52 per barrel.[7]

The wide range of these forecast prices are shown in Figures 1 and 2 below. ERA proposes to disregard the EIA low scenario as unrealistic since the forecast world oil prices through the year 2020 are substantially below current world oil prices.

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FIGURE 1

IMPORTED CRUDE OIL
PRICE FORECASTS

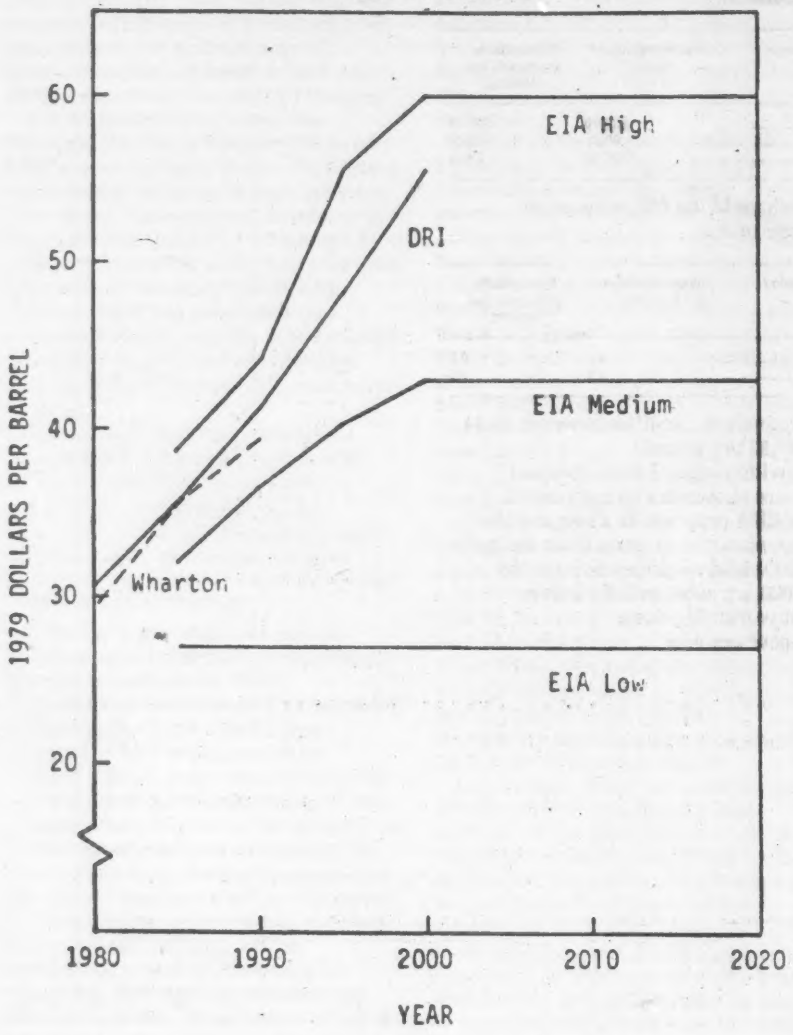


FIGURE 2

COAL PRICE FORECASTS

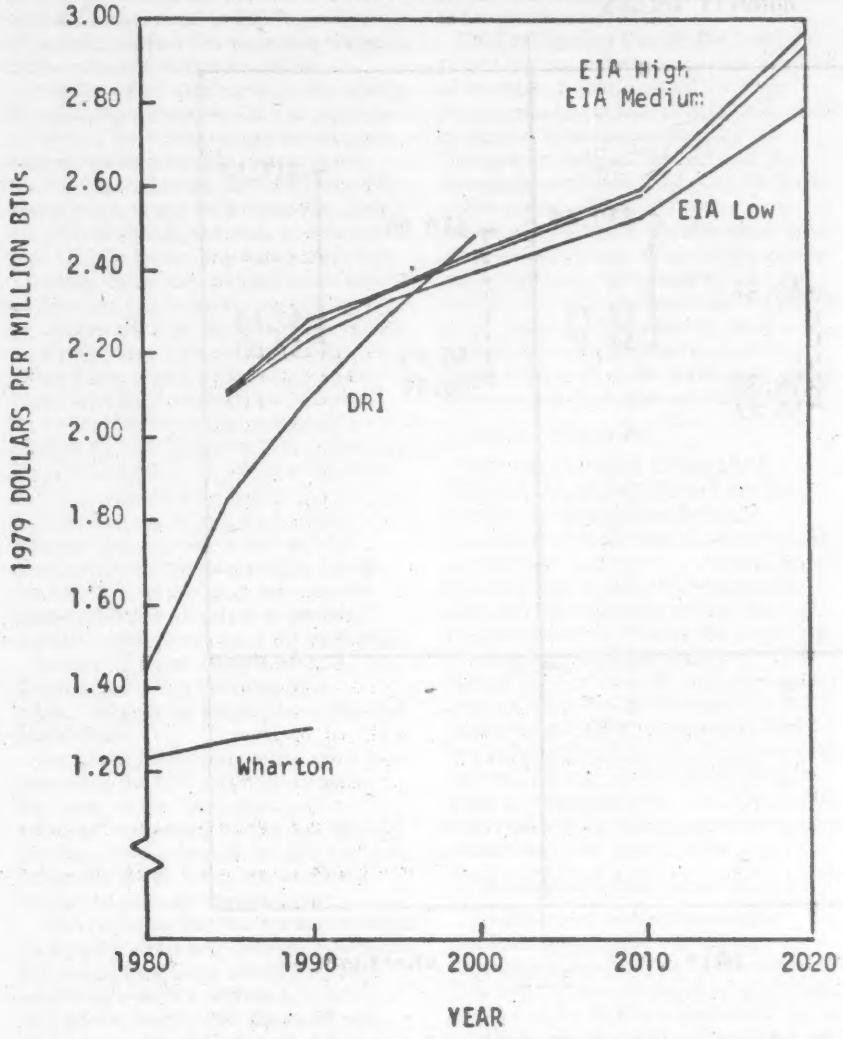
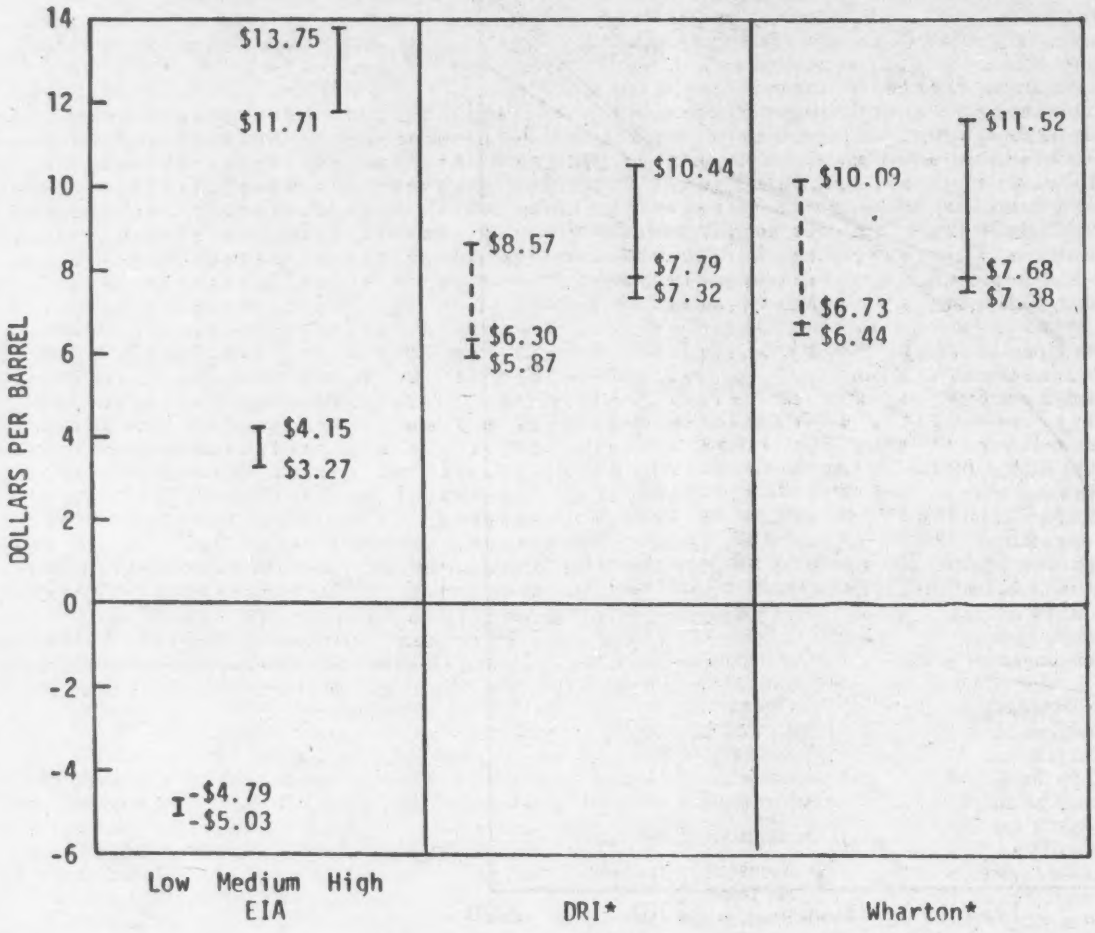


FIGURE 3

RANGES OF EQUIVALENT ANNUITY VALUES



* The solid line is based on a $32.20/bbl price of #6 fuel oil, the dashed line, on a $28.34/bbl price (see footnote 4). The three equivalent annuity values shown result from the three forecast extrapolation assumptions described in footnote 7.

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The equivalent annuity values, discussed above, associated with these forecasts are shown in Figure 3 above and range (except for the EIA low scenario) from $3.27 to $13.75 per barrel. ERA believes that the wide dispersion in these values is indicative of the uncertainty and varying outlooks among forecast organizations. ERA recognizes that all of the forecasts are based upon models which can only approximate reality. Nevertheless, ERA believes it is appropriate to use such forecasts, which are also available to firms, as a frame of reference in estimating future fuel price behavior. ERA does not believe it would be appropriate, however, to impose the maximum effect of these annuity values on a petitioner. Rather, ERA proposes, at this time, a limit of four dollars per barrel relating to the impact of future fuel prices, but recognizes that the amount to be adopted in a final rule may be different given the range of $3.27 to $13.75 per barrel covered by the forecasts examined by ERA. ERA believes this annuity value will be reasonable for the foreseeable future even in light of the large increase in imported crude oil prices relative to domestic coal prices over the past year.

In view of these factors, ERA is proposing the two versions of a methodology to be employed in the cost calculation.

For the explicit trajectories, ERA is proposing the EIA medium scenario forecasts as the "best practicable estimate" suggested by the Act. Should the trajectory approach be adopted (i.e., Appendix II–A), forecasts would be subject to periodic modification.

ERA believes that the exclusive use of an annuity alone has certain drawbacks. For example, a fixed annuity value would vary with a petitioner's actual fuel prices, facility life, discount rate, and the year the facility will go into service, thus the fixed premium would be representative of only a limited population and would overstate the annuity for existing facilities with shorter remaining lives.

Appendix II–A also proposes to employ a fixed annuity because of its simplicity, but allows the petitioer who would be disadvantaged because of relatively short useful facility life or other reasons to utilize explicit fuel price trajectories. Appendix II–B, however, proposes only the fixed annuity.

ERA requests comment on both versions of the methodology proposed in this notice: which appendix is appropriate; what values should be used for determining the fixed annuity value. In addition, which EIA scenario is most appropriate for determining explicit trajectories or should some other forecast or combination of forecasts be used. Finally, will the use of any per barrel limit result in distortions relative to the purposes of FUA.

ERA recognizes that on the basis of recent history, efforts to predict the rate of increase in world oil prices have projected a lower rate of price increases compared to actual world oil price changes. In view of this fact and the changing world conditions to which oil prices are sensitive, ERA intends to review its treatment of price trajectories on a periodic basis. After public notice and opportunity to comment, ERA may change the dollar amount attributable to price trajectory increases to be used in making the required cost calculations under FUA and/or the method by which such price trajectories are calculated.

(h) Natural gas price.

Sections 211(a)(1), 212(a)(1)(A), 311(a)(1) and 312(a)(1)(A) of the Act provide for exemptions from the prohibitions on the use of petroleum and natural gas "at a cost, . . . which, based upon the best practicable estimates, does not substantially exceed the cost, as determined by rule by the Secretary, of using imported petroleum. . . ." In light of the fact that the Act employs only an imported oil standard for this dual purpose, ERA is proposing that natural gas be prices, for purposes of the cost calculation, at the Btu equivalent price of #6 residual fuel oil (adjusted for imported prices) which meets air quality standards in the petitioner's area.

(i) Substantially exceeds premium.

As discussed in the Regulatory Analysis associated with these regulations, an analysis of the costs of U.S. dependence or imported oil being performed by DOE's Office of Policy and Evaluation for general policy purposes that are not limited to the FUA. That analysis includes an estimate, preliminarily, that an appropriate social premium, in the context of varying levels of risk of import disruptions, would range from $4 to $10 per barrel.[9] In theory, this is the value that should be associated with reducing the level of oil imports through DOE programs.

However, for purposes of the Fuel Use Act, as discussed in the Regulatory Analysis, it is unnecessary to incorporate the full amount of that social premium in addition to a fuel price escalation factor. ERA believes this to be appropriate since present information shows that no significant additional oil import savings would be generated by imposing a substantially exceeds premium of that magnitude at the present time. Nevertheless, in light of the statutory requirement that certain exemptions based on cost be granted only where that cost "substantially exceeds" the cost of imported oil, ERA is proposing a substantially exceeds premium of one dollar per barrel of petroleum fuel (approximately 3 percent of imported crude oil prices) which ERA believes is conservative at this time.

Comments are solicited on this value, and on whether, in the alternative, petitioners should bear the full cost of a social premium as currently estimated by DOE. ERA also solicits comments on alternative methods for determining the "substantially exceeds" premium. ERA intends to review the substantially exceeds premium on a periodic basis. After public notice and opportunity to comment, ERA may change the dollar amount attributable to the substantially exceeds premium to be used in making the required cost calculations under FUA and/or the manner by which such premium is established.

(j) Facility useful life

The cost calculation is essentially a comparison of life cycle costs discounted to the present. An important parameter is the lifetime over which the comparison will be made. For the purpose of FUA, it is the opinion of ERA that the relevant lifetime is an approximation of the physical life of the facility and not some other measure such as tax life. Therefore, ERA presumes that the useful life of all powerplants but nuclear is 35 years from the date of initial operation and that the useful life of a nuclear powerplant at 40 years. The useful life of an installation is presumed to be 40 years. These presumptions are rebuttable based on suitable engineering evidence provided by the petitioner or by ERA. Also, if the unit's remaining useful life is extended as a result of a conversion or refurbishment, that extension must be incorporated in the remaining useful life. Comments are invited on an appropriate presumption for the useful lives of combustion turbines and combined cycle units. Comments are also invited on the relationship between useful life and maintenance policy.

(k) Special cost test

For the purposes of obtaining a temporary exemption, ERA is proposing a special cost test, a comparison of discounted costs over the life of the exemption. (The general cost test, used for both temporary and permanent exemptions, is a comparison of discounted cost over the useful life of the unit.) Comments are requested on the need for a special cost test in addition to the general cost test.

(l) Consultation with State regulatory authorities

FUA provides at Section 103(a)(20) that DOE consult with appropriate State regulatory authorities on the determination of costs for powerplants. To implement this provision, ERA will submit copies of all petitions for powerplant exemptions which employ the cost calculation to the appropriate State regulatory authorities for review and will consider all comments made by these authorities before granting or denying a petition by final order. This proposed rule explicitly provides for this consultation.

(a) Written comments

The public is invited to participate in this rulemaking by submitting views, data, or arguments with respect to the proposal set forth in this Notice. Comments should be submitted to the address indicated in the "Addresses" section of this Notice and identified on the outside envelope and on each document with the designation "Calculation for the Cost of Using Alternate Fuel Under the Powerplant and Industrial Fuel Use Act on 1978." Fifteen copies should be submitted. All comments received will be available for public inspection in the Economic Regulatory Administration (ERA) Office of Public Information, Room B–110, 2000 M Street, N.W., Washington, D.C., between the hours of 8:00 a.m. and 4:30 p.m., Monday through Friday. Comments should be received by August 20, 1980, by 4:30 p.m.

Any information or data considered to be confidential must be also identified and submitted in writing, one copy only. ERA reserves the right to determine the confidential status of the information or data and to treat it according to its determination.

(b) Public hearings

(1) *Requesting opportunity for oral statement.* The time and place for the hearings are indicated in the "Dates" and "Addresses" sections of this Notice. If necessary to present all testimony, the hearings will be continued to 9:30 a.m. of the next business day following the first day of the hearings.

Any person may make a written request for an opportunity to make an oral presentation at the hearings. The requestor should provide a phone number where he may be contacted on the day before the hearings.

If selected to be heard, the requestor will be so notified by the DOE before 4:30 p.m. on the day before the hearing and is requested to submit at least 25 copies of the statement before 9:30 a.m. on the date of the hearing at the hearing location.

(2) *Conduct of the hearing.* ERA reserves the right to select the persons to be heard at the hearing, to schedule their respective presentations, and to establish the procedures governing the conduct of the hearing. The length of each presentation may be limited, based on the number of persons requesting to be heard. A DOE official will be designated to preside at the hearing, which will not be adjudicative in nature. Questions may be asked only by those conducting the hearing. At the conclusion of all initial oral statements, each person who has made an oral statement will be given the opportunity, if he or she so desires, to make a rebuttal statement. The rebuttal statements will be given in the order in which the initial statements were made and will be subject to time limitations.

Questions may be asked of any person making a statement at the hearing. Such questions should be submitted to the address indicated above for requests to speak before 4:30 p.m. on the day prior to the hearing. If at the hearing, a person decides that he would like to ask a question of a witness, the question must be submitted, in writing, to the presiding officer. In any case, the presiding officer will determine whether time limitations permit it to be presented for a response.

Any further procedural rule needed for the proper conduct of the hearing will be announced by the presiding officer.

Transcripts of the hearing will be made, and the entire record of the hearing, including the transcripts, will be retained and made available for inspection at the ERA Office of Public Information, Room B–110, 2000 M Street, N.W., Washington, D.C., between the hours of 8:00 a.m. and 4:30 p.m., Monday through Friday. Any person may purchase a copy of the transcript from the reporter.

In the event that it becomes necessary for ERA to cancel a hearing, every effort will be made to publish advance notice in the **Federal Register** of such cancellation. Moreover, actual notice will be given to all persons scheduled to testify at the hearing. However, it is not possible to give actual notice of cancellations or changes to persons not identified to ERA as participants. Accordingly, persons desiring to attend the hearing are advised to contact DOE on the last working day preceding the date of the hearing to confirm that it will be held as scheduled.

(c) Procedural matters

A draft regulatory analysis of this rule, as contemplated by Executive Order No. 12044, is attached as an appendix to these proposed rules. A Final Environmental Impact Statement (FEIS) has been prepared pursuant to the National Environmental Policy Act (NEPA). The FEIS may be obtained from the ERA Office of Public Information, Room B–110, 2000 M Street, N.W., Washington, D.C. 20461 (202) 653–4055.

These proposed rules must be submitted to the Office of Management and Budget (OMB) for clearance under the provisions of the Federal Reports Act. Any compliance with the data collection provisions of these rules may require revisions or additions as a result of OMB's action.

(Department of Energy Organization Act Pub. L. 95–91 Stat. 565 (42 U.S.C. 7101 *et seq.*); Powerplant and Industrial Fuel Use Act of 1978, Pub. L. 95–620, 92 Stat. 3289 (42 U.S.C. 8301 *et seq.*); E.O. 12009, 42 FR 46267)

Footnotes

1. For these forecasts, the equivalent annuity for a new powerplant will generally be higher due to the lower discount rate for utilities.

2. EIA price forecasts for the years 1985, 1990, and 1995 are for imported crude oil landed in the U.S. and industrial coal, assuming 22.5 MMBtu/ton. [*Draft Annual Report to Congress, 1979* (Volume III, Chapter 4, Table 4,2), EIA, April 1980]. For the years 2000–2020, the prices for world oil and industrial coal are from Chapter 5, Tables 5.1 and 5.5 of the same EIA publication.

3. The base prices used to calculate the 1980–1985 price increases for all three EIA scenarios were determined as follows:

Coal: The base price for coal in 1980 is $1.29/MMBtu, the national average price for coal delivered to steam-electric utility plants in December 1979 [*Monthly Energy Review* (DOE/EIA 0035/04(80)), April 1980, p. 89], adjusted to reflect delivered prices to industrial users, estimated by EIA to be $10.65/ton in 1979 dollars [*Preliminary 1985, 1990, and 1995 Energy Forecasts for the Annual Report to Congress, 1979* (Service Report SR/IA/80–01, April 1980), EIA, p. B–13].

Oil: The base price for imported crude oil in 1980 is $30.75/bbl, the January 1980 refiner acquisition cost for imported crude [*Monthly Energy Review* (DOE/EIA 0035/04 (80)), April 1980, p. 76].

Both these coal and oil prices from the *Monthly Energy Review* were adjusted to mid-1979 dollars (to conform to the mid-year price structure used by the EIA models) by using 50% of the GNP deflater of 9.8% [*Fiscal Year 1981 Budget Revisions,* Office of Management and Budget, March 1980, Table 2, p.8].

If the most recently available corresponding prices of oil and coal had been used, $32.40/bbl and $1.29/MMBtu, the February and January 1980 prices, respectively [*Monthly Energy Review* (DOE/EIA 0035/05 (80)), May 1980, pp. 77, 86], the projected rates of increase in imported oil for 1980–1985 would have been 2.7% (low), 0.8% (medium), and 4.3% (high), with equivalent annuities of −$5.82 to −$6.18, $1.96 to $2.67, and $10.13 to $11.97 per barrel, respectively.

4. The per barrel equivalent annuities for all the forecasts were calculated for an assumed new installation going on line in 1980 with a 40 year life using a 7.7% discount rate and the following fuel prices:

Coal: The coal price used, $11.24 per barrel of fuel oil equivalent, is the December 1979 price cited in footnote 3 above adjusted for delivery to industrial users.

Oil: the #6 residual fuel oil prices used were intended to reflect the range of possible residual oil prices. The higher the fuel oil price, the higher the equivalent annuity values and visa versa.

(a) $28.34 per barrel, the January 1980 price for 0.31 to 1.0 percent sulfur #6 fuel oil delivered to industrial users [*Monthly Energy Review* (DOE/EIA 0035/04 (80)), April 1980, p. 84]; and

(b) $26.26 per barrel, the national average price for #6 fuel oil in January 1980 plus $5.94, the (PICO—PCCO) adjustment for domestic petroleum for January 1980 (see Appendix II) for a total price of $32.20 per barrel [*Monthly Energy Review* (DOE/EIA 0035/04 (80)), April 1980, pp. 76, 84].

5. The equivalent annuity for a new powerplant with a 35 year life and a 2.9% discount rate is $4.43 per barrel, using the national average utility coal price of $1.29/MMBtu for December 1979 ($8.12 per barrel equivalent) and the national average utility #6 residual fuel oil price of $3.95/MMBtu for December 1979 ($24.82 per barrel) [*Monthly Energy Review* (DOE/EIA 0035/04 (80)), April 1980, p. 89].

6. *Energy Review,* Winter 1980 (Volume 4, Number 1), Data Resources, Inc., Table A–7 (average refiner acquisition cost for imported crude), p. 143; Table A–4 (bituminous coal price—new contract), p. 141; and Table A–3 (GNP deflator), p. 140.

7. In each forecast where the data do not extend to the year 2020, ERA extrapolated price behavior by applying three sets of assumptions:

(i) The rates of increase in oil and coal prices would increase at the last rate forecast (This results in the highest equivalent annuity);

(ii) The rates of increase would be zero beyond the last forecast date; and

(iii) The rate of increase for oil would be zero beyond the last forecast, but coal would continue to increase at the last forecast rate (yields the lowest equivalent annuity).

Applying these three assumptions yields an annuity ranges shown for the DRI and Wharton forecasts.

8. *Wharton Annual Model Pre-Meeting Solutions, April 1980,* Wharton Econometric Forecasting Associates, Inc., Table 24.61 (nominal prices for imported oil and domestically produced coal and the gross deflators for coal and crude oil), p. 85.

9. A $4 to $10 range would be the appropriate range if there were virtually no oil in strategic storage. A $2 to $6 range would be the appropriate range if there were several billion barrels of oil in strategic storage. At this time, ERA believes that the $4 to $10 range is the more appropriate.

In consideration of the foregoing, Subchapter E of Chapter II, Title 10 of the Code of Federal Regulations titled "Alternate Fuels," is proposed to be amended by addition of new Sections 503.6, 504.12 and 506.12 as set forth below.

Issued in Washington, D.C., on June 13, 1980

Hazel R. Rollins,

Administrator, Economic Regulatory Administration.

§ 503.6 Cost calculations for new powerplants and installations.

(a) *General.* (1) This calculation compares the cost of using alternate fuel to the cost of using imported petroleum. It must be performed for each alternate fuel and/or alternate site that the petitioner is required to examine.

(2) The cost of using an alternate fuel (see § 500.2) as a primary energy source will be deemed to substantially exceed the cost of using imported petroleum if the difference between the cost of using alternate fuel and the cost of using imported oil is greater than zero.

(3) There are two comparative cost calculations—a general cost test and a special cost test. Both take into consideration cash outlays for capital investments, annual expenses, and the effect of depreciation and taxes on cash flow. To demonstrate eligibility for a permanent exemption, a petitioner must use the procedures specified in the general cost test (paragraph (b) of this section). To demonstrate eligibility for a temporary exemption, the petitioner may apply the procedures specified in either the general cost test or the special cost test (paragraph (c) of this section).

(4) The general cost test differs from the special cost test with respect to (i) the time period over which costs are calculated, and (ii) the types of fuel-consuming equipment being considered. For the general cost test, the petitioner must compare the cost of using an alternate fuel in an alternate fuel capable unit with the cost of using oil or natural gas in an oil/natural gas capable unit over the lifetime of these facilities. For the special cost test, the petitioner must compare the cost of using alternate fuel against that of oil/natural gas in an alternate fuel capable unit over the period of the desired temporary exemption.

(b) *Cost calculation—general cost test.* (1) A petitioner may be eligible for a permanent exemption if he can demonstrate that the cost of using an alternate fuel from the first year of operation substantially exceeds the cost of using imported petroleum. Unless he can demonstrate that there are no factors that would materially alter the cost of using an alternate fuel during the first ten years of operation of the unit, the petitioner must also demonstrate that the cost of using an alternate fuel beginning at any time within the first ten years of operation, and using oil or natural gas until such time (*i.e.,* delayed use of alternate fuel), would substantially exceed the cost of using only imported petroleum.

(2) The petitioner would only be eligible for a temporary exemption, if the computed costs of delayed alternate fuel use commencing at the start of the second through eleventh years of operation do not always substantially exceed the cost of using only imported petroleum. The length of the temporary exemption would be the minimum period from the start of operation in which the cost of using alternate fuel substantially exceeds the cost of using imported petroleum.

(3) To conduct the test, calculate the difference (Delta) between the cost of using an alternate fuel (Cost(Alternate)) and the cost of using imported petroleum (Cost(Oil)) using Equations 1 through 3 below and the comparison procedures in paragraph (b)(5) of this section.

EQ 1 DELTA = COST (ALTERNATE) - COST (OIL)

where COST(ALTERNATE) and COST(OIL) are determined by:

$$\text{EQ 2} \qquad \text{COST} = I + \sum_{i=1}^{N} \frac{(OM_i + FL_i)(1-t)}{(1+k)^i}$$

and I (capital investment) is:

$$\text{EQ 3} \qquad I = \sum_{i=-g}^{N} \frac{I_i - ITC_i - S_i - t(DPR_i)\left(\frac{IX_e}{IX_i}\right)}{(1+k)^i}$$

(4) The terms in Equations 2 and 3 are defined as follows:

i = Year. Outlays before the unit becomes operational are future valued to the year before the unit becomes operational (year 0), and outlays after the unit becomes operational are present valued to the year before the unit becomes operational.

g = The number of years prior to the year before the unit becomes operational that a cash outlay is first made for capital investments or that an investment tax credit is first used.

N = The useful life of the unit (see paragraph (d)(5) of this section).

I_i = Yearly cash outlay (in dollars) from the year outlays first occur to the last year of the unit's useful life for capital investments. (See paragraph (d)(2) of this section for the items that must be included.)

OM_i = Annual cash outlays in year i (in dollars) for all operations and maintenance expenses except fuel (*i.e.*, all non-capital and non-fuel cash outlays caused by putting the capital investments (I) into service). This may include labor, materials, insurance, taxes (except income taxes), etc. (See paragraph (d)(3) of this section.)

S_i = Salvage value of capital investment (in dollars) in year i.

FL_i = Annual cash outlay for delivered fuel expenses (in dollars) in year i. (See paragraph (d)(3) of this section for FL calculation instructions and Appendix II of these regulations for the procedures to determine fuel price.)

k = The discount rate expressed as a fraction (see paragraph (d)(4) of this section).

ITC_i = Federal investment tax credit in year i resulting from capital investments used (see paragraph (d)(6) of this section).

DPR_i = Depreciation in year i resulting from capital investments (see paragraph (d)(6) of this section).

t = Marginal income tax rate (see paragraph (d)(6) of this section).

IX_i = Inflation index value for year i (see Table II-1 in Appendix II).

IX_e = Inflation index value for the year e, the year before the asset is placed in service.

(5) The step-by-step procedure that follows shows the comparison that the petitioner must make. It outlines the equipment, fuel, and time comparisons.

(i) Compute the cost of using an alternate fuel (COST (ALTERNATE)) in an alternate fuel-capable unit throughout the useful life of the unit using Equations 2 and 3.

(ii) Compute the cost of using oil or natural gas (COST (OIL)) in an oil or natural gas-fired unit throughout the useful life of the unit using Equations 2 and 3.

(iii) Using Equation 1, compute the difference (DELTA) between COST (ALTERNATE) and COST (OIL). If the difference (DELTA) is less than or equal to zero, a petitioner is not eligible for a permanent or temporary exemption using the general cost test and need not complete the remainder of the general cost test calculation. However, he still may be eligible for a temporary exemption using the special cost test (paragraph (c) of this section). If the difference (DELTA) is greater than zero and the petitioner can demonstrate that there are no factors that would materially alter the cost of using an alternate fuel during the life of the equipment, he has completed the test and is eligible for a permanent exemption. Otherwise he must complete the remainder of the general cost test—the delayed use calculations which follow.

(iv) Recompute COST (ALTERNATE) with Equations 2 and 3, assuming that an alternate fuel is not used as the primary energy source until the start of the second year of operation and that oil or natural gas is used for the first year of operation. All cash outlays should reflect postponed use of alternate fuel.

(v) Successively recompute COST (ALTERNATE) with Equations 2 and 3, assuming that the alternate fuel use is postponed until the start of the third year, fourth year, and so on, through the beginning of the eleventh year of operation (with oil or natural gas used in the years preceding alternate fuel use).

(vi) Compute the difference (DELTA) between each of the ten COST (ALTERNATE)s calculated in (iv) and (v) above and the COST (OIL) calculated in (ii) above.

(vii) If *all* the DELTAs computed in (iii) and (vi) above are greater than zero, the petitioner is eligible for a permanent exemption. If one or more of the DELTAs are less than or equal to zero, he is eligible for a temporary exemption for the period beginning at the start of the first year of operation and terminating at the beginning of the first year in which a DELTA is zero or less.

(c) *Cost calculations—special cost test.* (1) A petitioner may be eligible for a temporary exemption if he demonstrates that the cost of using an alternate fuel in an alternate fuel capable unit will substantially exceed the cost of using imported petroleum (or natural gas) in an alternate fuel capable unit over the period of the proposed exemption. The period of the proposed temporary exemption may not exceed ten years. The petitioner must demonstrate that the cost of using an alternate fuel substantially exceeds the cost of using imported petroleum for the first year of operation, the first two years of operation, and so forth, through the period of the proposed exemption. ERA will limit the duration of a temporary exemption to the shortest time possible.

(2) To conduct the test, calculate the difference (DELTA) between the cost of using an alternate fuel (COST (ALTERNATE)) and the cost of using imported petroleum (COST (OIL)) using Equations 4 and 5 below, Equation 3 (paragraph (b) of this section), and the comparison procedures in paragraph (c)(4) of this section.

EQ 4 DELTA = COST (ALTERNATE) - COST (OIL)

where COST(ALTERNATE) and COST (OIL) are determined by:

$$\text{EQ 5} \qquad \text{COST} = I \times \frac{\sum_{i=1}^{P} (1+k)^{-i}}{\sum_{i=1}^{N} (1+k)^{-i}} + \sum_{i=1}^{P} \frac{(OM_i + FL_i)(1-t)}{(1+k)^i}$$

Capital investment (I) is calculated with Equation 3 (paragraph (b)(3) of this section).

(3) The terms in Equation 5 are the same as those in Equation 2 with the addition of P, the length of the proposed temporary exemption.

(See paragraph (b)(4) of this section for other terms.)

(4) The step-by-step procedure that follows shows the comparisons which must be made.

(i) Using Equation 5, compute the cost of using an alternate fuel (COST (ALTERNATE)) in an alternate fuel-capable unit, assuming the length of the proposed exemption is one year.

(ii) Likewise, compute the cost of using oil or natural gas (COST(OIL)) in an alternate fuel and oil or natural gas-capable unit assuming the length of the proposed exemption is one year.

(iii) Compute the difference (DELTA) between COST(ALTERNATE) and COST(OIL) using Equation 4.

(iv) Repeat the calculations made in (i), (ii), and (iii) above, assuming the length of the proposed exemption is two years, three years, four years, and so on, up through the period of the proposed exemption.

(v) A petitioner is eligible for a temporary exemption for the period beginning at the start of the first year of operation and terminating at the beginning of the first year in which a DELTA is zero or less.

(d) *Information on parameters used in the calculations.* (1) All estimated expenditures, except fuel, shall be expressed in real (uninflated) terms by using the prices in effect at the time the petition is submitted. Instructions for fuel price calculations are contained in Appendix II.

(2) Capital investment yearly cash outlays (I_i) must include all items that are capital investments for Federal income tax purposes. All purchased equipment that has a useful life greater than one year, capitalized engineering costs, land, construction, environmental offsets, fuel inventory,[1] transmission facilities, piping, etc., that are necessary for the operation of the unit must be included. However, an item should only be included if a cash outlay is required after the decision has been made to build the unit.

(3)(i) The annual cash outlays for operations and maintenance expense (OM_i) and fuel expense (FL_i) for a powerplant may be computed by either of two methods; however, the one chosen must be consistently applied throughout the analysis:

(A) Assume the energy produced by the powerplant equals seventy (70) percent of design capacity times 8760 hours for each year during the life of the powerplant and compute cash outlays for operations, maintenance, and fuel expenses for the powerplant.

(B) Economically dispatch all powerplants in the region, including the new powerplant. The regional cash outlays for operations, maintenance, and fuel expenses (where oil and natural gas are evaluated at the price of imported petroleum) are the corresponding expenses for the purpose of the cost calculation. The region must be the petitioner's electrical region unless he can show that such integrated operation is unlikely to be achieved midway through the useful life of the powerplant, and he can propose an alternative acceptable to ERA.

(ii) When computing the annual cash outlays for operation and maintenance expense (OM_i) and fuel expense (FL_i) for in installation, specify the firing rates and the length of time each firing rate will be maintained.

(iii) If the petitioner's unit is a powerplant and he economically dispatches his region and an exemption is granted, he will have to certify, subject to penalties, that the proposed unit will not use more oil than he showed it would use in the dispatch analysis.

(iv) If the petitioner's unit is an installation, and an exemption is granted, he will have to certify, subject to penalties, that the proposed unit will burn no more oil than the maximum amount he could have specified and still have been granted an exemption.

(4) The discount rate (k) for analyses of powerplants is 2.9 percent. The discount rate (k) for analyses of installations is 7.7 percent. The inflation index (IX) is shown in Table II–1 of Appendix II. ERA will change this set of parameters from time to time after public notice and an opportunity to comment. Revisions shall become effective after final publication.

[1] The fuel inventory for powerplants will be: (a) all powerplants with only steam driven turbines—78 days. (b) all powerplants with only combustion turbines—162 days. (c) all powerplants with combined cycles—both steam driven turbines and combustion turbines—162 days. The fuel inventory for installations shall be presumed to be the greater of: (1) 21 days fuel supply, or (2) sufficient fuel to fill sixty (60) percent of the storage volume where whatever amount is chosen is equivalent in terms of number of days supply for both the base case and the alternate fuel case being compared. The petitioner may rebut the presumption of installation fuel supplies with suitable engineering evidence.

EQ 6 $$A = \frac{\sum_{i=1}^{Q} (1+k)^{-i}}{\sum_{i=1}^{R} (1+k)^{-i}}$$

where:

R = The useful life of the facility with the shorter life.

Q = The useful life of the facility with the longer life.

k = The discount rate (see paragraph (d)(4) above).

(6) All Federal investment tax credits (ITC_i) and depreciation (DPR_i) values are those used for Federal income tax purposes and must be applied consistently throughout the analysis and in a manner consistent with the Federal tax laws. All investment tax credits allowed under Federal tax law must be taken. In general, accelerated depreciation cannot be used for gas- or oil-fired boilers. Otherwise the petitioner must use the method of depreciation which results in the greatest present value of the cash flow due to the tax and depreciation effect. The marginal income tax rate (t) is the firm's marginal Federal income tax rate. The relevant investment tax credits, depreciation methodology, and marginal Federal income tax rates for a specific exemption petition will be those in effect at the time a decision is rendered.

(7) The design capacity of powerplants being compared must be the same. The maximum sustained energy per unit of time that could be produced by the installations being compared must be the same.

(8) All estimated cash outlays must be computed in accordance with generally accepted accounting principles consistently applied.

(9) The scope of the estimates of relevant costs (as discussed above) of units being compared must be the same.

(10) All allowances for uncertainty and risk in the cost estimates must be explicit.

(11) All petitions for powerplant exemptions involving the use of these calculations will be submitted to the appropriate State regulatory authorities for review. All comments made by such authorities will be considered before granting or denying a petition by final order.

(12) All cash outlays must be net of any government subsidies or grants.

(e) *Evidence in support of the comparative cost test.* All petitions for exemption requiring the use of the comparative cost test shall include, but not be limited to, the following information:

(1) A detailed accounting of all cash outlays, investment tax credits, and anticipated salvage for capital investments. Include a description of and cost estimate for all major construction and equipment. All critical assumptions should be stated and sufficient data included to support the petitioner's estimates.

(2) A detailed accounting of all annual cash outlays for fixed and variable operations and maintenance expenses including a description of all major elements and the formulas used to compute them. All critical assumptions should be stated and sufficient data included to support the petitioner's estimates.

(3) A detailed accounting of all annual cash outlays for delivered fuel expenses including the formulas used to compute them. All critical assumptions should be stated and sufficient data included to support the petitioner's estimates. The fuel price and characteristics for each alternate fuel should also be included.

(4) A detailed accounting of the depreciation for each capital asset, including the depreciable base, tax life, and methods used. All critical assumptions should be stated and sufficient data submitted to support the petitioner's estimates.

(5) If the useful lives that are presumptions (paragraph (d)(5)(i) above) are being rebutted, all critical assumptions and sufficient data necessary to support that position.

(6) If the petitioner has determined there are no factors that would materially alter the cost of using an alternate fuel over the life of the equipment, sufficient evidence to support this determination.

(7) If the petitioner's unit is an installation, a brief economic and technical justification of anticipated firing rates considering other units at the site.

§§ 504.12 and 506.12 Cost calculations for existing powerplants and installations.

(a) *General.* (1) This calculation compares the cost of using alternate fuel to the cost of using imported petroleum. It must be performed for each alternate fuel and/or alternate site that the petitioner is required to examine.

(2) The cost of using an alternate fuel (see § 500.2) as a primary energy source will be deemed to substantially exceed the cost of using imported petroleum if the difference between the cost of using alternate fuel and the cost of using imported oil is greater than zero.

(3) There are two comparative cost calculations—a general cost test and a special cost test. Both take into consideration cash outlays for capital investments, annual expenses, and the effect of depreciation and taxes on cash flow. To demonstrate eligibility for a permanent exemption, a petitioner must use the procedures specified in the general cost test (paragraph (b) of this section). To demonstrate eligibility for a temporary exemption, the petitioner may apply the procedures specified in either the general cost test or the special cost test (paragraph (c) of this section).

(4) The general cost test differs from the special cost test with respect to the time period over which costs are calculated. For the general cost test, the petitioner must compare the cost of using an alternate fuel with the cost of using oil or natural gas over the remaining useful life of the facility. For the special cost test, the petitioner must compare the cost of using alternate fuel against that of oil/natural gas over the period of the desired temporary exemption.

(5) ERA will use the procedures outlined in this section to perform part of the financial feasibility finding in §§ 504.5 and 506.2.

(b) *Cost calculation—general cost test.* (1) A petitioner may be eligible for a permanent exemption if he can demonstrate that the cost of using an alternate fuel from the first year of the exemption substantially exceeds the cost of using imported petroleum. Unless he can demonstrate that there are no factors that would materially alter the cost of using an alternate fuel during the first ten years of operation of the unit with an alternate fuel, the petitioner must also demonstrate that the cost of using an alternate fuel beginning at any time within the first ten years of the exemption, and using oil or natural gas until such time (*i.e.*, delayed use of alternate fuel), would substantially exceed the cost of using only imported petroleum.

(2) The petitioner would only be eligible for a temporary exemption, if the computed costs of delayed alternate fuel use commencing at the start of the second through eleventh years of operation from when alternate fuel would be used, do not always substantially exceed the cost of using only imported petroleum. The length of the temporary exemption would be the minimum period in which the cost of using alternate fuel substantially exceeds the cost of using imported petroleum.

(3) To conduct the test, calculate the difference (DELTA) between the cost of using an alternate fuel (COST(ALTERNATE)) and the cost of using imported petroleum (COST(OIL)) using Equations 1 through 3 below and the comparison procedures in paragraph (b)(5) of this section.

EQ 1 $$DELTA = COST(ALTERNATE) - COST(OIL)$$

where COST(ALTERNATE) and COST(OIL) are determined by:

EQ 2 $$COST = I + \sum_{i=-g}^{N} \frac{(OM_i + FL_i)(1-t)}{(1+k)^i}$$

and I (capital investment) is:

EQ 3 $$I = ID + \sum_{i=-g}^{N} \frac{I_i - ITC_i - S_i - t(DPR_i)\left(\frac{IX_e}{IX_i}\right)}{(1+k)^i}$$

(4) The terms in Equations 2 and 3 are defined as follows:

i=Year. Outlays before the proposed exemption becomes effective are future valued to the year before the proposed exemption becomes effective (year 0), and outlays after the proposed exemption becomes effective are present valued to the year before the proposed exemption becomes effective. In the case of the financial feasibility finding, year zero is the year before alternate fuel use would begin.

g=The number of years prior to the year before the proposed exemption becomes effective that (1) a cash outlay is first made for capital investments, (2) an investment tax credit is first used, or (3) replacement energy is required while the facility would be shut down for conversion.

N = The remaining useful life of the unit (see paragraph (d)(6) of this section).

ID = Capital investment required to recover "lost" capacity "Lost" capacity is the design capacity of a powerplant, or the maximum sustained energy per unit of time that could be produced by an installation, lost due to derating (see Equation 6, paragraph (d)(3) of this section). In the case of facilities that are not technicaly capable of burning alternate fuels, ID is the capital cost associated with an alternate fuel fired replacement facility of equal design capacity to the existing unit.

I_i = Yearly cash outlay (in dollars) from the year outlays first occur to the last year of the unit's useful life for capital investments. (See paragraph (d)(2) of this section for the items that must be included.)

OM_i = Annual cash outlay in year i (in dollars) for all operations and maintenance expenses except fuel (*i.e.*, all non-capital and non-fuel cash outlays. This may include labor, materials, insurance, taxes (except income taxes), etc. (See paragraph (d)(4) of this section.) Expenses for "replacement energy" may be accounted for under "OM_i". "Replacement energy" is that energy which substitutes for the output of a unit during the period of conversion to alternate fuel use.

S_i = Salvage value of capital investment (in dollars) in year i.

FL_i = Annual cash outlay for delivered fuel expenses (in dollars) in year i. (See paragraph (d)(4) of this section for FL_i calculation instructions and Appendix II of these regulations for the procedures to determine fuel price.) Expenses for fuel to generate "replacement energy" not treated in "OM_i" above may be accounted for here.

k = The discount rate expressed as a fraction (see paragraph (d)(5) of this section).

ITC_i = Federal investment tax credit used in year i resulting from capital investments (see paragraph (d)(7) of this section).

DPR_i = Depreciation in year i resulting from capital investments (see paragraph (d)(7) of this section).

t = Marginal income tax rate (see paragraph (d)(7) of this section).

IX_i = Inflation index value for year i (see Table II–1 in Appendix II).

IX_e = Inflation index value for the year e, the year before the asset is placed in service.

(5) The step-by-step procedure that follows shows the comparison that the petitioner must make. It outlines the equipment, fuel, and time comparisons.

(i) Compute the cost of using an alternate fuel (COST(ALTERNATE)) throughout the remaining useful life of the unit using Equations 2, 3, and 6.

(ii) Compute the cost of using oil or natural gas (COST(OIL)) throughout the remaining useful life of the unit using Equations 2 and 3.

(iii) Using Equation 1, compute the difference (DELTA) between COST (ALTERNATE) and COST(OIL). If the difference (DELTA) is less than or equal to zero, a petitioner is not eligible for a permanent or temporary exemption using the general cost test and need not complete the remainder of the general cost test calculation. However, he still may be eligible for a temporary exemption using the special cost test (paragraph (c) of this section). If the difference (DELTA) is greater than zero and the petitioner can demonstrate that there are no factors that would materially alter the cost of using an alternate fuel during the remaining useful life of the equipment, he has completed the test and is eligible for a permanent exemption. Otherwise he must complete the remainder of the general cost test—the delayed use calculations which follow.

(iv) Recompute COST(ALTERNATE) with Equations 2, 3, and 6, assuming that an alternate fuel is not used as the primary energy source until the start of the second year and that oil or natural gas is used for the first year. All cash outlays should reflect postponed use of alternate fuel.

(v) Successively recompute COST (ALTERNATE) with Equations 2, 3, and 6, assuming that the alternate fuel use is postponed until the start of the third year, fourth year, and so on, through the beginning of the eleventh year after the proposed exemption would be effective (with oil or natural gas used in the years preceding alternate fuel use).

(vi) Compute the differences (DELTA) between each of the ten COST (ALTERNATE)s calculated in (iv) and (v) above and the COST(OIL) calculated in (ii) above.

(vii) If *all* the DELTAs computed in (iii) and (vi) above are greater than zero, the petitioner is eligible for a permanent exemption. If one or more of the DELTAs are less than or equal to zero, he is eligible for a temporary exemption terminating at the beginning of the first year in which a DELTA is zero or less.

(c) *Cost calculations—special cost test.* (1) A petitioner may be eligible for a temporary exemption if he demonstrates that the cost of using an alternate fuel will substantially exceed the cost of using imported petroleum (or natural gas) over the period of the proposed exemption. The period of the proposed temporary exemption may not exceed ten years. The petitioner must demonstrate that the cost of using an alternate fuel substantially exceeds the cost of using imported petroleum for a period of one year, two years, three years, and so forth, through the period of the proposed exemption. ERA will limit the duration of a temporary exemption to the shortest time possible.

(2) To conduct the test, calculate the difference (DELTA) between the cost of using an alternate fuel (COST (ALTERNATE)) and the cost of using imported petroleum (COST (OIL)) using Equations 4 and 5 below, Equation 3 (paragraph (b) of this section), and the comparison procedures in paragraph (c)(4) of this section.

EQ 4 $$DELTA = COST\ (ALTERNATE) - COST\ (OIL)$$

where COST(ALTERNATE) and COST (OIL) are determined by:

EQ 5 $$COST = I \times \frac{\sum_{i=1}^{P} (1+k)^{-i}}{\sum_{i=1}^{N} (1+k)^{-i}} + \sum_{i=1}^{P} \frac{(OM_i + FL_i)(1-t)}{(1+k)^i}$$

Capital investment (I) is calculated with Equation 3 (paragraph (b)(3) of this section).

(3) The terms in Equation 5 are the same as those in Equation 2 with the addition of P, the length of the proposed temporary exemption. (See paragraph (b)(4) of this section for other terms.)

(4) The step-by-step procedure that follows shows the comparisons which must be made.

(i) Using Equation 5, compute the cost of using an alternate fuel (COST(ALTERNATE)) assuming the length of the proposed exemption is one year.

(ii) Likewise, compute the cost of using oil or natural gas (COST(OIL)) assuming the length of the proposed exemption is one year.

(iii) Compute the difference (DELTA) between COST(ALTERNATE) and COST(OIL) using Equation 4.

(iv) Repeat the calculations made in (i), (ii), and (iii) above, assuming the length of the proposed exemption is two

years, three years, four years, and so on, up through the period of the proposed exemption.

(v) A petitioner is eligible for a temporary exemption terminating at the beginning of the first year in which a DELTA is zero or less.

(d) *Information on parameters used in the calculations.* (1) All estimated expenditures, except fuel, shall be expressed in real (uninflated) terms by using the prices in effect at the time the petition is submitted. Instructions for fuel price calculations are contained in Appendix II.

(2) Capital investment yearly cash outlays (I_i) must include all items that are capital investments for Federal income tax purposes. All purchased equipment that has a useful life greater than one year, capitalized engineering costs, land, construction, environmental offsets, fuel inventory,[1] transmission facilities, piping, etc., that are necessary for the conversion of the unit must be included. However, an item should only be included if a cash outlay is required after the decision has been made to convert (or not convert) the unit.

(3)(i) Capital investment, if any, required to recover the design capacity or maximum sustained energy per unit of time that could be produced, lost due to derating or alternate fuel fired facility replacement (ID), must be computed with Equation 6 if it is elected to recover that capacity. COST computed with Equation 2 or 5 must yield the least cost solution.

[1] The fuel inventory for powerplants will be: (a) all powerplants with only steam driven turbines—78 days, (b) all powerplants with only combustion turbines—162 days, (c) all powerplants with combined cycles—both steam driven turbines and combustion turbines—162 days. The fuel inventory for installations shall be presumed to be the greater of: (1) 21 days fuel supply, or (2) sufficient fuel to fill sixty (60) percent of the storage volume where whatever amount is chosen is equivalent in terms of number of days supply for both the base case and the alternate fuel case being compared. The petitioner may rebut the presumption of installation fuel supplies with suitable engineering evidence. Include the salvage value of any fuel in inventory which cannot be used as a result of this conversion.

$$\text{EQ 6} \qquad ID = \frac{\sum_{i=1}^{N} (1+k)^{-i}}{\sum_{i=1}^{M} (1+k)^{-i}} \times \sum_{i=-g}^{M} \frac{ID_i - ITCD_i - SD_i - t(DPRD_i)\left(\frac{IX_e}{IX_i}\right)}{(1+k)^i}$$

(ii) M, ID_i, $ITCD_i$, SD_i, and $DPRD_i$ are the useful life, yearly investment cash outlays, investment tax credits, salvage values, and depreciation, respectively, resulting from the purchase of equipment required to recover the design capacity or maximum sustained energy per unit of time that could be produced, lost due to derating. All definitions and information which apply to N_i, I_i, ITC_i, S_i, and DPR_i (see paragraph (b)(4) of this section), also apply to M, ID_i, $ITCD_i$, SD_i, and $DPRD_i$, respectively, except that M, ID_i, $ITCD_i$, SD_i, and $DPRD_i$, are limited to equipment required to recover the loss due to derating. All other terms are as in Equation 3 (paragraph (b)(3) of this section). In the case of facilities that are not technically capable of burning alternate fuels, ID is the capital cost associated with an alternate fuel fired replacement facility of equal design capacity to the existing unit.

(iii) If an election is made not to recover the loss due to derating, ID equals zero.

(4)(i) The annual cash outlays for operations and maintenance expense (OM_i) and fuel expense (FL_i) for a powerplant may be computed by one of two methods; however, the one chosen must be consistently applied throughout the analysis. A third method identified in (C) below may be used for existing powerplants unless the energy generated by the alternate fuel fired powerplant calculated with method (C) is demonstrated to be less than that calculated with method (B) below.

(A) Assume the energy produced by the powerplant equals seventy (70) percent of design capacity times 8760 hours for each year during the remaining useful life of the powerplant and compute cash outlays for operations, maintenance, and fuel expenses for the powerplant.

(B) Economically dispatch all powerplants in the region, including the powerplant in which conversion to alternate fuel is being considered and, if applicable, the additional powerplant required due to derating or replacement. (In the event of a natural gas or oil fired powerplant which needs to be replaced due to technical inability to burn an alternate fuel, the replacement powerplant is a new alternate fuel fired powerplant of equal design capacity to the oil/natural gas fired unit. Economically dispatch all powerplants in the region including the existing facility for the COST(OIL) case. Economically dispatch all powerplants in the region without the existing unit but with the replacement unit for the COST(ALTERNATE) case.) The regional cash outlays or operating, maintenance, and fuel expenses (where oil and natural gas are evaluated at the price of imported petroleum) are the corresponding expenses for the purpose of the cost calculation. The region must be the petitioner's electrical region unless he can show that such integrated operation is unlikely to be achieved midway through the remaining useful life of the powerplant, and he can propose an alternate acceptable to ERA. If the design capacity lost due to derating or replacement is recovered, as discussed in paragraph (d)(3) of this section, the petitioner must employ this method for calculating operating, maintenance, and fuel expenses. The outlays for operations, maintenance, and fuel may also be estimated using a methodology that incorporates the benefits of economically dispatching units, and provides consistent treatment in the alternate fuel and oil/natural gas cases being compared.

(C) If the powerplant has been in operation for at least two years, assume that it will generate an amount of energy equal to the average amount of energy generated for the last five years (or the life of the powerplant if it is less than five years).

(ii) The annual cash outlays for operating and maintenance expenses (OM_i) and fuel expenses (FL_i) for an installation may be computed by the method specified in (A) below. A second method (B) may be used unless the energy or steam produced by the alternate fuel fired unit is demonstrated to be:

(A) Base the computations on the actual power or steam generation schedule of the installation in which conversion is being considered and, if applicable, the additional installation required due to derating of the facility being converted. If power output lost due to derating is recovered, see paragraph (d)(3) of this section, the petitioner must employ this method for calculating operating, maintenance, and fuel expenses.

(B) If the installation has been in operation for at least two years, assume it will annually generate an amount of

energy or steam equal to the average amount of energy or steam produced annually for the last five years (or the life of the installation if it is less than five years but at least two years).

(iii) If the petitioner's unit is a powerplant and he economically dispatches his region (or uses a historic capacity factor) and is granted an exemption, he will have to certify, subject to penalties, that the unit will not use more oil than he showed it would use in the dispatch analysis (or consistent with the historic capacity factor, if appropriate).

(iv) If the petitioner's unit is an installation, and an exemption is granted, he will have to certify, subject to penalties, that the unit will burn no more oil than the maximum amount he could have specified and still have been granted an exemption.

(5) The discount rate (k) for analyses of powerplants is 2.9%. The discount rate (k) for analyses of installations is 7.7%. The inflation index (IX) is shown in Table II–1 of Appendix II. ERA will change this set of parameters from time to time after public notice and an opportunity to comment. Revisions shall become effective after final publication. However, the relevant set of parameters for a specific petition for exemption will be the set in effect at the time the petition is submitted or the set in effect at the time a decision is rendered, whichever set is more favorable to the petitioner.

(6)(i) The remaining useful life (N) of a powerplant shall be presumed to be thirty-five (35) years minus the age of the plant when it would begin using an alternate fuel. The remaining useful life of a major fuel burning installation shall be presumed to be forty (40) years minus the age of the plant when it would begin using an alternate fuel. The petitioner or ERA may rebut this presumption with suitable engineering evidence. If the unit's remaining useful life is extended as the result of the conversion or refurbishment, that extension must be included in the remaining useful life.

(ii) If the life of a unit is extended, the petitioner will have to modify his calculation so that the two cash flows being compared have the length of the unextended remaining useful life. To do this, (1) use the unextended useful life in Equations 2 and 5 for the unit when it is both converted and unconverted, and (2) multiply capital investment term (I) for the converted unit (computed with Equation 3) by the following adjustment factor (A):

$$\text{EQ 7} \qquad A = \frac{\sum_{i=1}^{R} (1+k)^{-i}}{\sum_{i=1}^{Q} (1+k)^{-i}}$$

where:

Q=The extended remaining useful life of the facility.

R=The unextended remaining useful life of the facility longer.

k=The discount rate (see paragraph (d)(5) above).

(7) All Federal investment tax credits (ITC_i) and depreciation (DPR_i) values are those used for Federal income tax purposes and must be applied consistently throughout the analysis and in a manner consistent with the Federal tax laws. All investment tax credits allowed under Federal tax law must be taken. In general, accelerated depreciation cannot be used for gas- or oil-fired boilers. Otherwise the petitioner must use the method of depreciation which results in the greatest present value of the cash flow due to the tax and depreciation effect. The marginal income tax rate (t) is the firm's marginal Federal income tax rate. The relevant investment tax credits, depreciation methodology, and marginal Federal income tax rates for a specific exemption or financial feasibility finding will be those in effect at the time a decision is rendered.

(8) All estimated cash outlays must be computed in accordance with generally accepted accounting principles consistently applied.

(9) The scope of the estimates of relevant costs (as discussed above) of units being compared must be the same.

(10) All allowances for uncertainty and risk in the cost estimates must be explicit.

(11) All petitions for powerplant exemptions involving the use of these calculations will be submitted to the appropriate State regulatory authorities for review. All comments made by such authorities will be considered before granting or denying a petition by final order.

(12) All cash outlays must be net of any government subsidies or grants not already taken into account above.

(e) *Evidence in support of the comparative cost test.* All petitions for exemption requiring the use of the comparative cost test shall include, but not be limited to, the following information:

(1) A detailed accounting of all cash outlays, investment tax credits, and anticipated salvage for capital investments.

Include a description of and cost estimate for all major construction and equipment. All critical assumptions should be stated and sufficient data included to support the petitioner's estimates.

(2) A detailed accounting of all annual cash outlays for fixed and variable operations and maintenance expenses including a description of all major elements and the formulas used to compute them. All critical assumptions should be stated and sufficient data included to support the petitioner's estimates.

(3) A detailed accounting of all annual cash outlays for delivered fuel expenses including the formulas used to compute them. All critical assumptions should be stated and sufficient data included to support the petitioner's estimates. The fuel price and characteristics for each alternate fuel should also be included.

(4) A detailed accounting of the depreciation for each capital asset, including the depreciable base, tax life, and methods used. All critical assumptions should be stated and sufficient data submitted to support the petitioner's estimates.

(5) If the remaining useful life of an installation paragraph (d)(6)(i) above is being rebutted, all critical assumptions and sufficient data necessary to support that position.

(6) If the petitioner has determined there are no factors that would materially alter the cost of using an alternate fuel over the life of the equipment, sufficient evidence to support this determination.

(7) If the petitioner's unit is an installation, a brief economic and technical justification of the power or steam generation schedule considering other units at the site.

Appendix II–A—Fuel Price Computation

(a) *Introduction.* This appendix provides the equations and parameters needed to specify the price of delivered fuels used in the cost of using imported oil and the cost of using an alternate fuel in Parts 503, 504, and 506 of these regulations. The delivered price of oil or natural gas used to calculate delivered fuel expenses must reflect (1) the price of imported oil, (2) the effects of future real price increases in imported oil, and (3) the substantially exceeds premium. The delivered price of an alternate fuel used to calculate delivered fuel expenses must reflect the petitioner's delivered price of the alternate fuel and the effects of real price increases on the

price of alternate fuel. Paragraphs (b) and (c) below provide alternative procedures to account for projected real increases in the prices of fuels. The petitioner may compute his fuel prices by either of the procedures as long as the same procedure is applied consistently throughout the cost analysis. Table II-1 of this appendix contains the price indices used in option 1 (paragraph (b)) and the inflation index used in computing depreciation in Parts 503, 504, and 506 of these regulations. ERA will change the parameters specified in paragraphs (b)(6) and (c)(6) and in Tables II–1 and II–2 from time to time after public notice and an opportunity to comment. Revisions shall become effective after final publication. However, the relevant set of parameters for a specific petition for exemption will be the set in effect at the time the petition is submitted or the set in effect at the time a decision is rendered, whichever is more favorable to the petitioner.

(b) *Fuel price computation—option 1.* (1) If it is planned to use 100 percent domestic [1] petroleum product in the facility, the petroleum product price (PFE_i) is computed with Equation II–1.

$$\text{EQ II-1} \qquad PFE_i = (PF + PICO - PCCO)\left(\frac{OPX_i}{OPX_u}\right) + PREM$$

where:

PICO = Price of imported crude oil per barrel. The most recent refiner aquisition cost of imported crude oil as reported in the **Federal Register** monthly notice for the DOE Domestic Crude Oil Allocation (Entitlements) Program.[2]

PCCO = Price of composite crude oil per barrel. The most recent weighted average cost of total reported crude oil receipts as reported in the **Federal Register** notice for the DOE Entitlements Program.[2]

PF = The current market price of the petitioner's fuel oil per barrel (f.o.b. the facility). Alternatively, if the petitioner does not currently has a supplier of fuel oil or is using natural gas, he should use a simple average of the market prices of fuel oil available to him (capable of being burned in the facility and meeting air quality requirements) sold in his area by at least three suppliers.

PFE_i = Price of fuel oil per barrel in year i.

OPX_i = Oil price index value for year i (see Table II–1).

OPX_u = Oil price index value for year u in which the petition is submitted.

PREM = Substantially exceeds premium added to the price of oil (see paragarph (b)(6) below).

(2) If it is planned to use 100 percent imported petroleum product in the facility, the petroleum price (PFE_i) is computed with Equation II–2.

$$\text{EQ II-2} \qquad PFE_i = (PF + ENT)\left(\frac{OPX_i}{OPX_u}\right) + PREM$$

The terms in Equation II–2 are the same as those or Equation II–1 with the addition of:

ENT = ½ × EP × DOSR for residual fuel oil if an entitlement has been received by the importer, or 0 for all other products or if an entitlement has not been received by the importer.[2]

EP = Entitlement price reported in the **Federal Register** monthly notice for the DOE Entitlements Program.

DOSR = National domestic oil supply ratio reported in the **Federal Register** monthly notice for the DOE Entitlements Program.

(3) If it is planned to use a combination of domestic and imported petroleum product in the facility, use a weighted average of the prices computed with Equations II–1 and II–2. If it cannot reasonably be estimated what fraction of petroleum product is imported, assume that 100 percent of it is domestically refined.

(4) If it is planned to use natural gas in the facility, Equation II–1 and II–2 must be used, as appropriate, to calculate the price of fuel (PFE_i), along with the price of the No. 6 residual fuel oil (PF) which meets the air quality standards in the petitioner's area.

(5) The delivered price of alternate fuel (PFA_i) must reflect the real escalation rate of alternate fuel and must be computed with Equation II–3.

$$\text{EQ II-3} \qquad PFA_i = APF\left(\frac{APX_i}{APX_u}\right)$$

The terms of Equation II–3 are defined as follows:

PFA_i = Price of alternate fuel in year i.

APF = The current market price of the alternate fuel (f.o.b. the facility).

APX_i = Alternate fuel price index value of year i (see Table II–1).

APX_u = Alternate fuel price index for the year u in which the petition is submitted (see Table II–1).

(6) The petitioner shall use the following parameters for Equations II–1, II–2, and II–3 of this appendix:

(i) The substantially exceeds premium, PREM, is $1.00 per barrel of oil equivalent.

(ii) The oil price index values, OPX_i and OPX_u, are specified in Table II–1.

(iii) The alternate fuel price index values, APX_i and APX_u, depend on the type of alternate fuel to be used.

(A) If the alternate fuel is solid coal, the petitioner must use the alternate fuel price index for coal in Table II–1.

(B) For all other alternate fuels, the petitioner may use either the alternate fuel price index for coal in Table II–1 or his own substantiated escalation rates and the equation for OPX_i in Footnote 3 to this appendix.

(c) *Fuel price computation—option 2.* (1) If it is planned to use 100 percent domestic [1] petroleum product in the facility, the petroleum product price (PFE_i) is computed with Equation II–4.

EQ II–4 $PFE_i = (PF + PICO - PCCO) + PREM + FUTR$

where:

PICO = Price of imported crude oil per barrel. The most recent refiner aquisition cost of imported crude oil as reported in the **Federal Register** monthly notice for the DOE Domestic Crude Oil Allocation (Entitlements) Program. [2]

PCCO = Price of composite crude oil per barrel. The most recent weighted average cost of total reported crude oil receipts as reported in the **Federal Register** notice for the DOE Entitlements Program.[2]

PF = The current market price of the petitioner's fuel oil per barrel (f.o.b. the facility). Alternatively, if the petitioner does not currently have a supplier of fuel oil or is using natural gas, he should use a single average of the market prices of fuel oil available to him (Capable of being burned in the facility and meeting air quality requirements) sold in his area by at least three suppliers.

PFE_i = Price of fuel oil per barrel in year i.

PREM = Substantially exceeds premium added to the price of oil (see paragraph (c)(6) below).

FUTR = Premium added to the price of oil to account for projected escalation in oil prices as compared to escalation in alternate fuel prices (see paragraph (c)(6) below).

(2) If it is planned to use 100 percent imported petroleum product in the facility, the petroleum price (PFE_i) is computed with Equation II–5.

EQ II–5 $PFE_i = (PF + ENT) + PREM + FUTR$

The terms in Equation II–5 are the same as those of Equation II–4 with the addition of:

ENT = ½ × EP × DOSR for residual fuel oil if an entitlement has been received by the importer, or 0 for all other products or if an

entitlement has not been received by the importer.[2]

EP = Entitlement price reported in the **Federal Register** monthly notice for the DOE Entitlements Program.

DOSR = National domestic oil supply ratio reported in the **Federal Register** monthly notice for the DOE Entitlements Program.

(3) If it is planned to use a combination of domestic and imported petroleum product in the facility, use a weighted average of the prices computed with Equations II–4 and II–5. If it cannot reasonably be estimated what fraction of petroleum product is imported, assume that 100 percent of it is domestically refined.

(4) If it is planned to use natural gas in the facility, Equations II–4 and II–5 must be used, as appropriate, to calculate the price of fuel (PFE_i), along with the price of the No. 6 residual fuel oil (PF) which meets the air quality standards in the petitioner's area.

(5) The price of alternate fuel (PFA) must be the current market price of the alternate fuel (f.o.b. the facility).

(6) The petitioner shall use the following parameters for Equations II–4 and II–5 of this appendix.

(i) The substantially exceeds premium, PREM, is $1.00 per barrel of oil equivalent.

(ii) The premium added to the price of oil to account for projected escalation in oil prices compared to escalation in alternate fuel prices, FUTR, is $4,000 per barrel of oil equivalent.

Table II–1.—*Price and Inflation Indices for Use in the Cost Calculations* [3]

Year	Crude oil price index (OPX)	Alternative fuel price index for coal (APX)	Inflation index (IX)
1980	1.000	1.000	1.000
1981	1.016	1.039	1.096
1982	1.032	1.080	1.189
1983	1.049	1.122	1.281
1984	1.066	1.165	1.369
1985	1.083	1.211	1.453
1986	1.111	1.229	1.525
1987	1.140	1.247	1.586
1988	1.169	1.266	1.634
1989	1.200	1.285	1.683
1990	1.231	1.304	1.733
1991	1.257	1.316	1.785
1992	1.283	1.328	1.839
1993	1.310	1.340	1.894
1994	1.338	1.352	1.951
1995	1.366	1.364	2.009
1996	1.386	1.372	2.070
1997	1.407	1.381	2.132
1998	1.428	1.389	2.196
1999	1.449	1.397	2.262
2000	1.471	1.406	2.329
2001	1.471	1.414	2.399
2002	1.471	1.422	2.471
2003	1.471	1.431	2.545
2004	1.471	1.440	2.622
2010	1.471	1.492	3.131
2011	1.471	1.512	3.225
2012	1.471	1.531	3.321
2013	1.471	1.551	3.421
2014	1.471	1.571	3.524
2015	1.471	1.592	3.629
2016	1.471	1.612	3.738
2017	1.471	1.633	3.850
2018	1.471	1.655	3.966
2019	1.471	1.676	4.085
2020	1.471	1.698	4.207
2021	1.471	1.720	4.333
2022	1.471	1.742	4.463
2023	1.471	1.765	4.597
2005	1.471	1.448	2.700
2006	1.471	1.457	2.781
2007	1.471	1.466	2.865
2008	1.471	1.474	2.951
2009	1.471	1.483	3.039
2024	1.471	1.788	4.735
2025	1.471	1.811	4.877

Footnotes

1. For the purposes of these regulations, the Virgin Islands, Puerto Rico, the U.S. territories and possessions, and all the States are domestic sources.

2. When the DOE Entitlements Program is terminated, PICO, PCCO, and ENT will all equal zero.

3. The index values OPX, APX, and IX in Table II–1 were calculated using the rates (see Table II–2) for the real increase in oil price (Ro), coal price (Ra), and inflation (INF), respectively, and the following equations:

$$OPX_i = \prod_{j=1980}^{i} (1 + Ro_j)$$

$$APX_i = \prod_{j=1980}^{i} (1 + Ra_j)$$

$$IX_i = \prod_{j=1980}^{i} (1 + INF_j)$$

where:

i = Year of index, and

$\prod$ = Product of terms with index i ranging from j = 1980 to i.

If the petitioner chooses to supply his own escalation rates for an alternate fuel, as provided in option 1 (paragraph (b)(6)(iii)(B) and (C) of Appendix II), he must use these equations to calculate the appropriate index values.

Table II–2.—*Rates of Fuel Price Increase and Inflation Used in Table II–1*

Year (j)	Ro	Ra	INF
1980	0.000	0.000	0.000
1981	0.016	0.039	0.096
1982	0.016	0.039	0.085
1983	0.016	0.039	0.077
1984	0.016	0.039	0.069
1985	0.016	0.039	0.061
1986	0.026	0.015	0.050
1987	0.026	0.015	0.040
1988–1990	0.026	0.015	0.030
1991–1995	0.021	0.009	0.030
1996–2000	0.015	0.006	0.030
2001–2010	0.000	0.006	0.030
2011–2025	0.000	0.013	0.030

Appendix II–B—Fuel Price Computation

(a) *Introduction.* This appendix provides the equations and parameters needed to specify the price of delivered fuels used in the cost of using imported oil and the cost of using an alternate fuel in Part 503 of these regulations. The delivered price of oil or natural gas used to calculate delivered fuel expenses must reflect (1) the price of imported oil, (2) the effects of future real price increases in imported oil, and (3) the substantially exceeds premium. The delivered price of an alternate fuel used to calculate delivered fuel expenses must reflect the petitioner's delivered price of the alternate fuel and the effects of real price increases on the price of alternate fuel. Paragraph (b) below provides procedures to account for projected real increases in the prices of fuels. Table II–1 of this appendix contains the inflation index used in computing depreciation in Part 503 of these regulations. ERA will change the parameters specified in paragraph (b)(6) and in Tables II–1 and II–2 from time to time after public notice and an opportunity to comment. Revisions shall become effective after final publication. However, the relevant set of parameters for a specific petition for exemption will be the set in effect at the time the petition is submitted or the set in effect at the time a decision is rendered, whichever is more favorable to the petitioner.

(b) *Fuel price computation.* (1) If it is planned to use 100 percent domestic[1] petroleum product in the facility, the petroleum product price (PFE_i) is computed with Equation II–1.

EQ II–1 $PFE_i = (PF + PICO - PCCO) + PREM + FUTR$

where

PICO = Price of imported crude oil per barrel. The most recent refiner acquisition cost of imported crude oil as reported in the **Federal Register** Monthly notice for the DOE Domestic Crude Oil Allocation (Entitlements) Program.[2]

PCCO = Price of composite crude oil per barrel. The most recent weighted average cost of total reported crude oil receipts as reported in the **Federal Register** notice for the DOE Entitlements Program.[2]

PF = The current market price of the petitioner's fuel oil per barrel (f.o.b. the facility). Alternatively, if the petitioner does not currently have a supplier of fuel oil or is using natural gas, he should use a simple average of the market prices of fuel oil available to him (capable of being burned in the facility and meeting air quality requirements) sold in his area by at least three suppliers.

PFE_i = Price of fuel oil per barrel in year i.

PREM = Substantially exceeds premium added to the price of oil (see paragraph (b)(6) below).

FUTR = Premium added to the price of oil to account for projected escalation in oil prices as compared to escalation in alternate fuel prices (see paragraph (b)(6) below).

(2) If it is planned to use 100 percent imported petroleum product in the facility, the petroleum price (PFE_i) is computed with Equation II–2.

EQ II–2 $PFE_i = (PF + ENT) + PREM + FUTR$

The terms in Equation II–2 are the same as those of Equation II–1 with the addition of:

ENT = ½ × EP × DOSR for residential fuel oil if an entitlement has been received by the importer, or 0 for all other products or if an entitlement has not been received by the importer.[3]

EP = Entitlement price reported in the **Federal Register** monthly notice for the DOE Entitlements Program.

DOSR = National domestic oil supply ratio reported in the **Federal Register** monthly notice for the DOE Entitlements Program.

(3) If it is planned to use a combination of domestic and imported petroleum product in the facility, use a weighted average of the prices computed with Equations II–1 and II–2. If it cannot reasonably be estimated what fraction of petroleum product is imported, assume that 100 percent of it is domestically refined.

(4) If it is planned to use natural gas in the facility, Equations II–1 and II–2 must be used, as appropriate, to calculate the price of fuel (PFE_i), along with the price of the No. 6 residual fuel oil (PF) which meets the air quality standards in the petitioner's area.

(5) The price of alternate fuel (PFA) must be the current market price of the alternate fuel (f.o.b. the facility).

(6) The petitioner shall use the following parameters for Equations II–1 and II–2 of this appendix:

(i) The substantially exceeds premium, PREM, is $1.00 per barrel of oil equivalent.

(ii) The premium added to the price of oil to account for projected escalation in oil prices compared to escalation in alternate fuel prices, FUTR, is $4.00 per barrel of oil equivalent.

Table II–1—Inflation Indices for Use in the Cost Calculations[1]

Year	Inflation Index (IX)
1980	1.000
1981	.096
1982	1.189
1983	1.281
1984	1.369
1985	1.453
1986	1.525
1987	1.586
1988	1.634
1989	1.683
1990	1.733
1991	1.785
1992	1.839
1993	1.894
1994	1.951
1995	2.009
1996	2.070
1997	2.132
1998	2.196
1999	2.262
2000	2.329
2001	2.399
2002	2.471
2003	2.545
2004	2.622
2005	2.700
2006	2.781
2007	2.865
2008	2.951
2009	3.039
2010	3.131
2011	3.225
2012	3.321
2013	3.421
2014	3.524
2015	3.629
2016	3.738
2017	3.850
2018	3.966
2019	4.085
2020	4.207
2021	4.333
2022	4.463
2023	4.597
2024	4.735
2025	4.877

Footnotes

1. For the purposes of these regulations, the Virgin Islands, Puerto Rico, the U.S. territories and possessions, and all the States are domestic sources

2. When the DOE Entitlements Program is terminated, PICO, PCCO and ENT will all equal zero.

3. The inflation index values (IX) in Table II–1 were calculated using inflation rates (INF) (Table II–2) provided by the Office of Management and Budget and the following equation:

$$\text{EQ II-3} \qquad IX_i = \prod_{j=1980}^{i} (1 + INF_j)$$

where:

i = Year of index, and

$\prod$ = Product of terms with index i ranging from j = 1980 to i.

Table II-2—Rate of Inflation Used in Table II-1

Year (j)	INF
1980	0.000
1981	0.096
1982	0.085
1983	0.077
1984	0.069
1985	0.061
1986	0.050
1987	0.040
1988–2025	0.030

Final Regulatory Analysis for Certain Purposes and Draft Regulatory Analysis for Purposes of the Cost Calculations

I. Introduction

The Economic Regulatoty Administration (ERA) of the Department of Energy (DOE) has issued the final rule to implement the provisions of the Powerplant and Industrial Fuel Use Act of 1978 (FUA). ERA has also reissued a Notice of proposed rulemaking on the cost calculation provisions of FUA. The purpose of this analysis is to set forth the policy objectives of FUA, the general statutory provisions mandated by Congress to achieve these objectives, the alternative methods examined by ERA to fulfill this mandate, and the rationale upon which the final regulations and proposed cost calculation regulations are based.

ERA considers the regulatory analysis final for all aspects of FUA except the cost calculations, and as a draft regulatory analysis for the cost calculations.

II. Policy Objectives

FUA is an integral part of the National Energy Act and represents an expansion of the authority contained in the Energy Supply and Environmental Coordination Act of 1974. The primary purpose of FUA is to minimize the use of petroleum and natural gas in industrial boilers and powerplants, thereby reducing the Nation's dependence on imported fossil fuels and encouraging use of indigenous energy resources, particularly coal and other alternate fuels. The statutory provisions by which this broad purpose and the other objectives of the Act are to be achieved include:

- prohibition on petroleum and natural gas use in new facilities;
- prohibition on construction of new electric powerplants that cannot burn coal or another alternate fuel;
- prohibition on natural gas use as a primary energy source by new electric powerplants after January 1, 1990;
- prohibition on natural gas use by existing powerplants before January 1, 1990, unless natural gas was a plant's primary energy source during 1977;
- prohibition on natural gas use by existing powerplants in greater proportion than their historic use of this fuel; and
- authorization of DOE to issue rules or orders prohibiting existing facilities from using petroleum or natural gas and from using excessive amounts of these fuels in mixtures.

Further, FUA authorizes DOE to exempt a powerplant or an industrial installation from these statutory prohibitions if certain physical, economic, environmental, or legal factors preclude compliance with them. The final rule establishes criteria that must be met to obtain an exemption, with the burden of proof that an exemption is warranted resting on the petitioner, not on DOE. The policy objectives of these criteria and of DOE's overall design in the final regulations to implement FUA is to minimize the use of oil and natural gas and, where these fuels must be used, to insure that they are used efficiently.

III. Impact Analysis

The purpose of this section is to describe the analyses which have been done in support of FUA, their results, and the decisions made based on these results in the final rule and the proposed rule on the cost calculations.

Two aggregate analyses, a microeconomic analysis, and two social benefit analyses have been performed and are summarized here.

A. Aggregate Analysis of FUA

The quantitative impacts of policy alternatives available to DOE in implementing the Fuel Use Act were assessed by the Energy Information Administration (EIA) of DOE in two analyses. The findings of the first analysis were reported in an analysis memorandum, "Analysis of Proposed DOE Regulations Implementing the Powerplant and Industrial Fuel Use Act" [AM/EI/79–07 (November 1978)], and were also discussed in the draft regulatory analysis for FUA (43 FR 54058–61, November 17, 1978).

The second EIA analysis was performed at the request of ERA and the Council on Wage Price Stability (COWPS), with the results reported in "MEFS Runs Describing Alternative Implementation of the Powerplant and Industrial Fuel Use Act" [SR/IA/79–15 (October 1979)] and "Modified MEFS Runs Describing Alternative Implementations of the Powerplant and Industrial Fuel Use Act" [SR/IA/79–11 (October 1979)]. The Regulatory Analysis Review Group (RARG) [1] filed extensive comments on the implications of this EIA analysis; these comments are in the public file of this rulemaking and were also discussed in the preamble to the interim regulations (44 FR 28954–56, May 17, 1979).

This second analysis attempted to capture the effects of the significantly higher oil prices which had come into existence since the first EIA analysis. Relying primarily on DOE's MEFS (Mid-Term Energy Forecasting System) model and on IFCAM (Industrial Fuel Choice Analysis Model), developed by Economic and Environmental Analysis, Inc., EIA examined three scenarios, all with higher oil prices, two with dollar increments added to the price of oil [2] and one without. The results of these iterations showed much smaller impacts from FUA than did the earlier analysis described above. The base case scenario, a "minimal regulatory program" assumed coal use would only be required for units covered by the Act if coal use were no more costly on a life cycle basis than oil use (taking account of expected changes in fuel prices). It showed oil and gas savings of about 0.5 quadrillion Btu per year for industrial installations in 1990, but only negligible net import savings to the energy system. A second, more stringent cost test iteration, with an increment of $1 per barrel added to the cost of oil, resulted in changes in fuel use so small as to be below the resolution of the model. The third version, with a $2 increment, resulted in 1990 savings of only 0.014 quadrillion Btu per year over the "minimal regulatory program." Furthermore these iterations indicated

[1] RARG is a permanent regulatory review group composed of representatives of several agencies located within the Executive Office of the President. It was established to monitor the performance of regulatory agencies under the provisions of Executive Order No. 12044, "Improving Government Relations."

[2] This increment corresponds to the substantially exceeds cost premium suggested by the Act (Sections 211(a)(1), 212(a)(1)(A), 311 (a)(1), and 312(a)(A)).

that FUA would back out imported gas rather than imported oil.

The results of these analyses, as in all analyses, are limited by the assumptions which are used to derive them, and after carefully reviewing the assumptions used to model implementation of the Fuel Use Act, ERA decided that the analyses were inadequate.

These were several of the inadequacies:

- The forecasts for residential and commercial gas demand appear to be too low, given the cost of competing fuels.
- The industrial boiler retirement and construction rates assumed in the absence of FUA are unduly optimistic in light of recent boiler sales statistics; thus the pace of industrial conversion to coal is too high.
- The assumption that utilities would replace oil and natural gas capacity with new coal capacity when costs made it economic to do so, overstates the likely pace of electric utility conversions to coal. The forecast does not pay adequate attention to PUC behavior and the impact of financial constraints on utility investment for any purposes other than meeting load growth.

Further, DOE has observed that regulatory uncertainty and the additional burden of operating complex coal systems (when compared to oil and gas systems) tend to limit the use of coal, an additional factor which was unforeseen in the MEFS parameters. DOE has also concluded that the MEFS estimates of oil imports saved by natural gas backed out as the result of FUA are questionable. RARG analysis of MEFS indicated that only 0.69 Btu of imported oil would be saved for each Btu of gas displaced by FUA. However, the combined effect of the assumptions used in EIA's analysis is to provide very low projections of gas demand relative to supply. The effect of underestimating demand is to underestimate gas prices, and at lower prices, gas displaced by FUA may not reduce oil imports. Because of the limitations on MEFS modeling and the fact that oil and natural gas are excellent substitutes, DOE concludes that natural gas displaced by FUA would result in oil displacement.

In summary, the two EIA aggregate analyses were of only limited usefulness in evaluating the effects of FUA. From them, DOE concluded that FUA would reduce the amount of imported petroleum to some extent and that in a high oil/coal price differential environment, the effect of an increment added to the price of oil would be small. These uncertain results led ERA to perform further analysis.

B. Microeconomic Analysis of FUA

The effects of FUA were examined by ERA after it became apparent that the usefulness of the aggregate analyses were limited. ERA used its limited experience with initial petitions submitted under the interim regulations to infer the broad classes of facilities (by size and application) that would be required to burn an alternate fuel, given both the effects of increasingly higher fuel escalation rates and a substantially exceeds increment added to the price of oil. DOE found that:

(1) A $4/bbl addition [1] to the current cost of fuel based on world oil prices [2] would result in:
—virtually all new powerplants, except peakload units, having to use coal or nuclear power,
—most new industrial boilers at new sites having to use coal, and
—new, large industrial boilers replacing or expanding existing facilities and operating at least two shifts per day having to use coal.

(2) A $6/bbl addition [1] would have an impact (over and above $4) resulting in:
—older existing coal-capable powerplants converting to coal, and
—new industrial boilers replacing or expanding existing facilities and operating at least one shift per day having to use coal (given minimal site restrictions).

(3) A $8/bbl addition [1] would have an impact (over and above $6) resulting in:
—new industrial boilers replacing or expanding existing facilities, operating one shift per day, and having an atypical capital cost and/or additional site restrictions, having to use coal, and
—new industrial boilers with gasifiers operating continuously at new sites, having to use low-Btu coal gasification.

This analysis is limited because of incomplete data and because ERA has not been able to quantify the amounts of imported petroleum saved at each level of stringency. However, it does give some indication of what types of individual facilities would likely be impacted which could not be done by the aggregate analyses.

C. Social Benefits of FUA

There are very real benefits to be gained for the United States by reducing petroleum imports. DOE's Office of Policy and Evaluation analysed the benefits of reduced oil imports described in the preamble to the interim FUA regulations (44 FR 28955–56, May 17, 1979) under the headings "Oil Import Reduction Premium," "National Security Benefits," "Balance of Payments Benefits" and "Legal Emissions Under the Clean Air Act," incorporated here by reference.

A completely different analysis has been substituted for the prior analysis, and was performed so as to provide a fresh point of departure for the proposed rule. This analysis was based on the concept of a "social premium" as the most straight-forward way of signaling the market place that imported oil costs more to the economy than its per-barrel price.

This new analysis is part of a continuing study being performed for general policy purposes in the Office of Policy and Evaluation (P&E) [Preliminary results of the analysis are reported in "The Energy Problem: Costs and Policy Options," dated May 23, 1980 (Staff Working Paper), Office of Gas and Integrated Analysis, Policy and Evaluation, Department of Energy. A copy of this paper will be included in the public file.]. This preliminary analysis examined the energy problem in the context of high and uncertain prices, vulnerability to supply disruptions, and vulnerability to strategic threats of disruption used to gain foreign policy, military, or economic concessions by analyzing three different world views with varying levels of risk of disruptions.

The major goal of the analysis was to quantify certain general policy conclusions:

- that very large strategic oil stockpiles should be built rapidly if serious future disruptions are anticipated;
- that contingency plans, such as a very high short term tariff, should be used to mitigate the cost of disruption if one occurs; and
- that measures beyond deregulation of energy prices should be taken to reduce imports.

Only the quantification of this last conclusion, which is discussed below, is directly relevant to the substantially exceeds premium used in FUA.

For this social premium analysis, P&E relied in part on EIA forecasts which suggest that a five dollar increase in oil prices would reduce imports by a million barrels per day within seven years. This relationship between costs and import reductions was combined with an examination of the benefits of varying levels of import reduction in several situations:

- different estimates of the risk of a disruption,
- different degrees of preparation to deal with a disruption through contingency plans and draw-downs from a strategic petroleum stockpile,
- differing amounts of common action by our allies, and
- other policies to promote import reductions such as natural gas deregulation, oil

[1] This addition to the cost of fuel as calculated in the FUA cost tests has two components, one attributable to the additive effect of the substantially exceeds cost premium. The other component is the present value of future increases in real fuel prices calculated as an annuity.

[2] From a base price of $30 per barrel.

backout programs in the utility sector, and conservation programs.

In general, the analysis found that the premium level should be higher when there is a greater risk of disruption, less effective preparation to deal with a disruption, a higher level of oil imports, more cooperation among allies, or an inadequate package of other policies to promote import reductions. It also provided several overlapping ranges of estimates of the social premium, varying between $4 and $10.[1] The appropriate range could be selected to suit a view on the risks of an import disruption based on answers to certain questions about long term energy policy, *e.g.*, will we stockpile oil and develop contingency plans, will there be effective cooperation among our allies, etc. As all of these questions cannot be answered at this time, DOE has not yet settled upon a particular probabilistic estimate of the risks of disruption.

This P&E analysis did not attempt to re-estimate separately the social benefits of balance of payments changes from reduced oil imports or the costs of increased legal air emissions under the Clean Air Act. The analysis did estimate the price effect from lower world oil prices (a result of decreased demand) and the benefits from decreased vulnerability to sudden supply disruptions (a result of decreased reliance on interruptible foreign supplies). The size of these particular components of the premium can be quite sensitive to specific conditions in the world petroleum market. However, the size of the aggregate premium is less sensitive to market conditions as influences on different components tend to be off-setting. The security component tends to be greatest when the price effect is smallest, and vice versa. If OPEC matches any U.S. demand reduction with decreased production in order to maintain prices, then security component will be large. If OPEC maintains production, then the U.S. or its allies will continue to be dependent on OPEC oil and the security component will be small, but prices will necessarily fall in order for OPEC to maintain production levels in the face of reduced demand.

D. Decision Summary

There are several key decisions which will determine the impact of FUA. These are:

- future fuel prices and how they are specified for the cost calculation,
- the appropriate level of substantially exceeds cost premium in the cost test,
- exemption by certification, and
- definition of primary energy source.

1. *Specification of fuel prices.* The Act requires exemption applicants to compare the present value costs of using alternate fuel to those of using imported oil. To implement this provision, ERA had to determine how to specify future fuel price behavior and how to equate natural gas to the mandated imported oil cost standard.

a. *Future fuel prices.* DOE believes imported oil prices will increase faster than inflation. ERA could propose a cost calculation which accounts for explicit increases in fuel prices in the future. Alternatively, ERA could propose that a single annuity value be used to represent future increases in petroleum over coal prices, or a combination of these two approaches. ERA believes that use of explicit increase in prices is conceptually more precise than a single premium, which does not accurately account for the varying remaining lifetimes of existing facilities nor the impact of the different discount rates used for utilities and industrial firms.

ERA examined a variety of recent fuel price projections, those published by the DOE Energy Information Administration and two widely used private forecasting services—Data Resources, Inc. (DRI) and Wharton Econometric Forecasting Associates (Wharton).

As discussed in the preamble to the proposed cost calculation rule, ERA computed the equivalent premium associated with each forecast for a new industrial facility[1] and found that these premiums ranged from $5.03 per barrel to $13.75 per barrel. Because of the wide variation in these forecasts of future price behavior, ERA is proposing what it believes to be a reasonably conservative limit of a four dollar per barrel annuity added to the price of petroleum.

ERA is also proposing adoption of specific fuel price escalation rates and has chosen the EIA "Medium Scenario" as the most appropriate to FUA implementation at this time subject to the limit discussed above. Should a fuel price escalation approach be adopted, the escalation rates would be subject to periodic modification after public notice in light of more recent forecasts.

ERA is requesting comment on which price forecast or forecasts should be used and whether the concept of an annuity "limit" discussed makes sense or, in the alternative, that petitioners be required to bear the full cost associated with the best practicable forecasts available to ERA.

b. *Natural gas price.* The statutory cost test requires the comparison between alternate fuel and imported oil and does not specifically mention how natural gas should be treated.

In the proposed rule, natural gas is priced equivalent to #6 residual fuel oil in conformity with the regulations issued under the Natural Gas Policy Act (NGPA). ERA will continue to examine the ramifications of this decision, particularly as it impacts the FUA requirement for powerplants to be off natural gas by 1990.

2. *Level of substantially exceeds premium.* The preliminary analysis performed by the Office of Policy and Evaluation discussed earlier estimated that, in the context of varying levels of risk of disruption of oil imports, an appropriate social premium would range from $4 up to $10. This is estimated to be the value that should be associated with reductions in the level of oil imports. However, in the case of the Fuel Use Act, current information suggests that it is unlikely that significant additional oil imports savings would be generated by imposing the full amount of the social premium in addition to the fuel price escalation factor based on the EIA medium scenario.

Therefore, in light of the statutory requirements that the cost exemption be granted only if the cost of an alternate fuel substantially exceeds the cost of imported oil, ERA is proposing adoption of a conservative premium of $1 per barrel at this time. ERA is also soliciting comments on whether petitioners should bear the full cost associated with current DOE estimates of the social premium.

3. *Exemption by certification.* The first year of experience with FUA implementation has convinced ERA that certain mandatory exemptions would lend themselves to a certification process whereby the petitioner who certifies to specified eligibility requirements, specified terms and conditions, and operation of the unit only after all applicable environmental permits are approved would automatically be granted the exemption.

The following permanent exemptions will be available by certification under certain conditions:

- peakload exemption for combustion turbines;
- available supply of alternate fuel exemption for industrial installations operated less than 600 hours per year;
- scheduled outages exemption for industrial installations used less than an average of 28 days per year over three years;

[1] A $4 to $10 range would be the appropriate range if there were virtually no oil in strategic storage. A $2 to $6 range would be the appropriate range if there were several billion barrels of oil in strategic storage. At this time, ERA believes that the $4 to $10 range is the more appropriate.

[1] The premium is equal to an equivalent annuity added to the price of imported petroleum for a facility with a 40 year life and 7.7% discount rate.

- mixtures exemption for industrial installations using mixtures of less than 25 percent oil and natural gas as their primary energy source; and
- emergency exemption.

The petitioner is spared the time and cost to prepare the detailed environmental data previously required for these exemptions and the regulatory burden is reduced for both the petitioner and ERA. It should be stressed, however, that DOE has not at this point categorically excluded the above exemptions from the NEPA process. Before doing so, DOE must amend its NEPA guidelines, allowing for public notice and comment in the process. In the event that such amendment does not take place, the portions of these regulations dealing with NEPA compliance for limited use exemptions would be revised accordingly. ERA expects to periodically re-examine the specific criteria for these exemptions, revise them after due notice and comment, and possibly expand the concept to other mandatory exemptions.

4. *Definition of primary energy source.* The Act prohibits the use of oil and natural gas as a primary energy source. ERA could require all users of alternate fuel to report on their use of oil and gas to insure minimal use of these fuels. However, ERA believes imposition of this administrative burden is generally unnecessary since the high price differential between oil and coal will tend to limit excessive oil and gas use in alternate fuel fired units. Consequently, ERA has set a rebuttable threshold of fifteen (15) percent of total energy use below which no reporting requirement is imposed.

E. Future Directions

1. *Regulatory evolution.* ERA is fully aware of the limitations of its analyses and the uncertainties associated with the costs and benefits of the FUA program as now promulgated and considering today's economic environment. Consequently, ERA will continue to monitor the relevance and effectiveness of the parameters adopted in the final rules. In particular, ERA will periodically update those parameters associated with the cost test (e.g., discount rates, projected future price escalation rates, projected rates of inflation, etc.).

In addition, ERA hopes to use its programmatic experience to simplify the regulations by providing, if possible, more mandatory certification exemptions, fine-tuning the regulatory language of exemptions and definitions, and developing alternative regulatory/programmatic options tailored to the exigencies of the petitioner (*e.g.*, examination of a unit within a firm-wide context to maximize efficient conversions within the firm).

2. *Regional impacts.* The EIA analysis memorandum "Analysis of Proposed DOE Regulations Implementing the Powerplant and Industrial Fuel Use Act" (cited above), discussed the regional impact of FUA. The major impact of the Act is associated with the requirement that natural gas fired powerplants must be off gas by 1990. This "off-gas" provision is expected to have a significant impact on the Southwest, where natural gas is currently being used for considerable amounts of baseload electrical generation. One concern is that these powerplants may shift from natural gas to a petroleum product fuel by 1990 (which is permissible under the Act). ERA has some flexibility under Title V of FUA (System Compliance) to affect a gradual phasedown in natural gas use beyond 1990. Also, utilities may seek exemption under Title III (Existing Facilities Exemptions). Any further redress of these localized regional impacts would require additional legislation, however.

ERA is also convinced that the treatment of the cogeneration exemption under FUA has regional implications. In certain regions, ERA expects that oil and natural gas will continue to be used for baseloaded electrical generation in the near term. In these regions, ERA believes that certain amounts of cogeneration can clearly achieve near term oil/gas savings since efficient cogenerated electricity would replace that generated by less efficient existing units. ERA is examining mechanisms that would include the involvement of approriate State officials and simplify the procedures by which petitioners may qualify for a cogeneration exemption, while ensuring that the new cogeneration facilities displace existing, less efficient oil and gas fired electrical generation, and not new alternate fuel fired generation.

ERA's exercise of discretionary authority to require coal capable powerplants currently using oil to revert to coal will largely impact the Northeast. However, ERA believes that these reversions will generally reduce the cost of electricity on a life cycle basis due to the current large differential between coal and oil prices.

3. *Sunset review.* ERA believes that the recent rapid escalation in world oil prices raises issues relative to FUA. When the Administration originally submitted the National Energy Act to Congress in 1977, the industrial and utility sector switch out of oil and gas was to be accomplished through (a) a user tax on oil and gas use, (b) financial incentives for alternate fuel use, and (c) a regulatory program. The taxes and incentives were intended to be the principal forces to shift private decision making away from oil and gas use, while the regulatory program was viewed as a backstop. FUA, the resulting regulatory program, and a portion of the financial incentives were the only measures enacted. However, the rapid increase in world oil prices has resulted in a radical change in the private sector decision making process in favor of coal and other alternate fuel use. Hence FUA may prove to be limited in its marginal effectiveness, given the current economic incentives to use alternate fuels. Therefore, ERA intends to monitor the program's progress and its continuing viability in the context of the statutory purposes of FUA to promote efficient use of oil and natural gas, use of alternate fuels where economic, and reduction of oil imports.

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